ELECTRIC

ELECTRIC PERSPECTIVES
The Magazine for Management in America's Investor-Owned Electric Utilities

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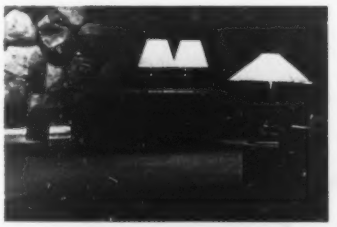

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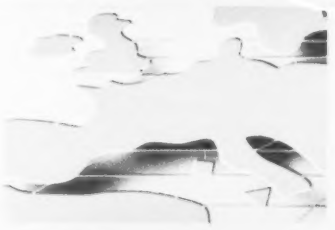

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Cover photo by Russell Abraham, courtesy of Luminae-Souter.

FINANCIAL REVIEW

SECOND QUARTER EARNINGS DROP 6.5 PERCENT

Lower sales and accruals combined to push investor-owned electric utility earnings per share before extraordinary items down from $0.46 for the second quarter of 1991 to $0.43 for the second quarter of 1992. Earnings after extraordinary items and inclusive of non-recurring items fell from $0.47 to $0.42, a drop of 10.6 percent. (See Table 1.)

Due partly to the 1.3 percent decrease in sales caused by the unseasonably mild weather and faltering economic recovery that characterized the second quarter, total electric operating revenues edged down slightly, from $37.8 billion to $37.7 billion, while total electric operating expenses edged up, from $30.7 billion to $30.8 billion. A 7.4 percent decrease in fuel expense helped offset significant increases in expenses for purchased power & net interchange (7.2 percent) and depreciation & amortization (4.1 percent).

The $545 million decrease in fuel expenses, the largest drop for this line item experienced since the fourth quarter of 1986 and the seventh consecutive quarterly decrease, is related to the $266 million increase in purchased power expenditures: to reduce regulatory and construction risks, companies have adopted power supply strategies that that rely more heavily on purchased power. According to the Energy Information Administration, for electric utilities both the costs for receipts and the aggregate purchases of coal, oil, and natural gas were down for the first five months of this year compared to last year.

The downward trend in allowance for funds used during construction (AFUDC) and phase-in accruals also continued. Together they contributed $162 million less to net income in the second quarter of 92 than they did in 91. As a percentage of net income, AFUDC represented 8.3 and phase-ins represented 1.0.

Dropping $126 million, net interest expenses and charges also continued their downward trend, reaching a four-year low despite the decline in borrowed AFUDC accruals. The drop reflects the growing number of refinancings undertaken to lower the yields and shorten the maturities of long-term debt. As a result, the industry's pre-tax interest coverage ratio with AFUDC improved from 2.48 times for the year ending June 30, 1991, to 2.54 times for the year ending June 30, 1992.

The result of one company's paying $101 million of preferred dividends in arrears, preferred dividends declared increased by $93 million over the second quarter of 1991. Otherwise, those quarterly dividends would have continued their downward trend. Common stock dividends declared increased 6.9 percent, from $3.4 billion to $3.6 billion on a quarter-to-quarter basis. Common dividends per share rose 4.4 percent, from $0.45 to $0.47. Dividend increases by many companies, the reinstatement of dividend payments by two companies, and increases in common stock issuance combined to produce the increase.

Construction work in progress (CWIP) jumped 8.6 percent from June 30, 1991, to June 30, 1992. (See Table 2.) As a percentage of net plant in service, CWIP rose to 6.4 from 6.0. It was boosted by the costs associated with the construction of a single nuclear unit.

Investments increased 10.7 percent over the period, growing from $27.8 billion to $30.7 billion. Utility plant rose 3.3 percent.

The common equity capitalization ratio increased from 43.0 percent on June 30, 1991, to 43.2 percent a year later. The increased issuance of common stock, rising 3.7 percent, was the primary contributor to the increase. Retained earnings increased only 0.1 percent. The portion of preferred stock in the industry's capitalization ratio slid from 7.4 to 7.1 percent. Long-term debt increased 2.2 percent, inching it as a percentage of capitalization from 49.6 percent at the end of the second quarter last year to 49.7 percent at the end of the second quarter this year.

Tables 1 and 2 are based on unaudited reports submitted by a sample representing all investor-owned electric utility companies. Supplemented with Standard & Poor's Utility Compustat II Database Service, data are revised to reflect all company restatements.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

Table 1
Investor-Owned Electric Utility Industry Statement of Income
(Millions of Dollars)

	Three Months Ending June 30,			Twelve Months Ending June 30,		
	1992	1991r	% Change[3]	1992	1991r	% Change[3]
Total Electric Operating Revenues[1]	$37,741	$37,803	(0.2)	$157,864	$153,517	2.8
Electric Operating Expenses						
Fuel	$6,796	$7,341	(7.4)	$29,620	$31,355	(5.5)
Purchased Power & Net Interchange	3,984	3,718	7.2	15,201	13,935	9.1
Other Operation & Maintenance	10,627	10,605	0.2	42,771	41,030	4.2
Depreciation & Amortization	4,265	4,098	4.1	16,879	15,953	5.8
Costs Deferred Under Rate Phase-In Plans	6	(62)	N.M.	(74)	(408)	(81.8)
Taxes Other Than Income Taxes	3,146	2,993	5.1	12,787	11,903	7.4
Income Taxes: Federal & Other	1,492	1,742	(14.4)	7,956	7,487	6.3
Deferred Income Taxes	576	351	64.1	1,987	1,925	3.2
Investment Tax Credits, Net	(125)	(66)	89.8	(308)	(208)	48.0
Total Electric Operating Expenses	$30,767	$30,720	0.2	$126,819	$122,972	3.1
Electric Operating Income	$6,974	$7,083	(1.5)	$31,046	$30,545	1.6
Other Utility Operating Income	165	187	(11.6)	1,206	1,225	(1.6)
Total Utility Operating Income	$7,140	$7,270	(1.8)	$32,251	$31,770	1.5
Other Income & Deductions, Net	$500	$526	(4.9)	($957)	($734)	30.5
Phase-in Deferrals	47	115	(58.8)	257	574	(55.2)
Allowance for Other Funds Used During Construction	146	155	(5.9)	601	855	(29.8)
Total Income Before Interest Charges	$7,833	$8,066	(2.9)	$32,151	$32,466	(1.0)
Interest Charges						
Interest on Long-Term Debt	$3,716	$3,804	(2.3)	$15,161	$15,348	(1.2)
Other Interest Expenses & Charges	359	413	(13.1)	1,527	1,711	(10.8)
Allowance for Borrowed Funds Used During Construction	(127)	(144)	(11.7)	(551)	(712)	(22.6)
Net Interest Expenses & Charges	$3,947	$4,073	(3.1)	$16,136	$16,347	(1.3)
Net Income Before Extraordinary Items	$3,886	$3,993	(2.7)	$16,015	$16,119	(0.6)
Extraordinary Items	(12)	4	N.M.	(348)	(24)	1,322.4
Cumulative Effect of a Change in Accounting Principle	0	76	N.M.	110	184	(40.3)
Net Income	$3,873	$4,072	(4.9)	$15,777	$16,279	(3.1)
Preferred Dividends Declared	574	481	19.4	2,062	1,952	5.7
Net Income Available for Common	$3,300	$3,592	(8.1)	$13,715	$14,327	(4.3)
Common Dividends Declared	3,643	3,407	6.9	14,290	13,441	6.3
Additions to Retained Earnings	($344)	$184	N.M.	($575)	$885	N.M.
Average Shares Outstanding (Millions)	7,787	7,654	1.7	7,662	7,599	0.8
Earnings Per Share Before Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle[2]	$0.43	$0.46	(6.5)	$1.82	$1.86	(2.2)
Earnings Per Share After Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle[2]	$0.42	$0.47	(10.6)	$1.79	$1.89	(5.3)
Common Dividends Per Share[2]	$0.47	$0.45	4.4	$1.86	$1.77	5.1

Source: Edison Electric Survey Data and Standard & Poor's Compustat II Database Service.
[1]Revenues are adjusted for intra-industry electricity sales for resale.
[2]Based on average shares outstanding as reported to Edison Electric Institute by survey respondents and adjusted for stock splits.
[3]Percent changes may reflect independent roundings.
r-Revised to reflect company restatements.
N.M.-Not Meaningful.

Table 2
Investor–Owned Electric Utility Industry Balance Sheet
(Millions of Dollars)

Assets	June 30, 1992	June 30, 1991r	% Change[2]
Utility Plant[1]			
Utility Plant (Including Nuclear Fuel)	$541,392	$523,892	3.3
Less Accumulated Depreciation	176,210	162,543	8.4
Total	$365,182	$361,349	1.1
Construction Work in Progress	23,455	21,593	8.6
Net Utility Plant	$388,638	$382,943	1.5
Investments	30,743	27,771	10.7
Current Assets	44,389	44,276	0.3
Deferred Debits	38,460	36,149	6.4
Total Assets	$502,230	$491,139	2.3
Capitalization & Liabilities			
Capitalization			
Common Stock	$98,766	$95,256	3.7
Retained Earnings	53,437	53,357	0.1
Preferred Stock	25,045	25,545	(2.0)
Long-Term Debt	175,014	171,170	2.2
Total Capitalization	$352,262	$345,328	2.0
Current Liabilities			
Short-Term Debt	$10,929	$12,162	(10.1)
Long-Term Debt Due Currently	11,186	9,447	18.4
Other Current Liabilities	34,617	34,791	(0.5)
Total Current Liabilities	$56,732	$56,399	0.6
Deferred Credits			
Capital Lease Obligations, Non–Current Portion	$3,366	$3,717	(9.4)
Accumulated Deferred Income Taxes	54,842	52,542	4.4
Accumulated Deferred Investment Tax Credits	14,575	15,232	(4.3)
Other Deferred Credits	20,453	17,921	14.1
Total Deferred Credits	$93,237	$89,412	4.3
Total Capitalization & Liabilities	$502,230	$491,139	2.3

Source: Edison Electric Institute Survey Data and Standard & Poor's Compustat II Database Service.
[1]Includes non-electric plant.
[2]Percent changes may reflect independent roundings.
r-Revised to reflect company restatements.

STATISTICAL REVIEW

SECOND QUARTER SALES DOWN 1.3 PERCENT

Unusually mild temperatures and the faltering economic recovery combined to dampen second quarter electricity sales. Sales to ultimate customers by investor-owned electric utilities for the quarter totaled only 497.8 million MWh (megawatthours), a 1.3 percent drop from the 504.4 million sold during the second quarter of 1991. Sales to weather-sensitive residential customers saw the sharpest decline (5.1 percent). Commercial sales slid 0.9 percent while industrial sales actually increased 1.4 percent.

The increase in industrial sales, from 178.7 million to 181.3 million MWh, reflects the weak economic recovery underway during the second quarter: real gross domestic product (in 1987 dollars) grew only 1.5 percent. Similarly, the drop in residential and commercial sales reflects the cooler-than-usual weather that characterized the quarter: cooling degree days were 14.4 percent lower than normal. Moreover, compared to the same period in 1991, cooling degree days fell 37.6 percent this year.

Nonetheless, revenues for the first quarter declined only $176.6 million, dipping 0.5 percent from $35.1 billion to $34.9 billion. Again, industrial customers led the way, contributing the highest percentage increase in revenues 2.1 and growing in number by 2.2 percent.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

Table 1
Second Quarter Customer, Sales, and Revenue Data for Investor-Owned Electric Utilities

	Three Months Ending June 30,			Twelve Months Ending June 30,		
	1992	1991	% Change	1992	1991	% Change
Number of Customers						
Residential	75,246,425	74,382,379	1.2	74,985,405	74,169,665	1.1
Commercial	9,436,748	9,334,255	1.1	9,402,599	9,324,779	0.8
Industrial	402,088	393,447	2.2	397,970	393,759	1.1
Street & Highway	148,513	144,754	2.6	147,252	143,003	3.0
Other Public Authorities	172,223	169,026	1.9	170,955	163,058	4.8
Railroads	23	23	0.0	23	23	0.0
Interdepartmental	672	464	44.8	519	464	11.9
Total Customers	85,406,692	84,424,348	1.2	85,104,723	84,194,751	1.1
Electricity Sales (MWh)						
Residential	147,993,471	155,996,985	(5.1)	684,877,783	680,578,215	0.6
Commercial	150,897,384	152,290,692	(0.9)	623,766,136	618,081,881	0.9
Industrial	181,267,551	178,712,306	1.4	722,012,678	715,051,094	1.0
Street & Highway	2,453,852	2,448,994	0.2	10,556,589	10,480,673	0.7
Other Public Authorities	14,242,343	14,035,793	1.5	56,082,883	52,131,770	7.6
Railroads	609,263	634,159	(3.9)	2,507,654	2,540,576	(1.3)
Interdepartmental	310,734	293,153	6.0	1,253,716	1,079,054	16.2
Total Sales	497,774,598	504,412,082	(1.3)	2,101,057,439	2,079,943,263	1.0
Revenues ($000)						
Residential	12,981,627	13,390,551	(3.1)	58,538,088	56,711,114	3.2
Commercial	11,775,208	11,728,689	0.4	48,403,799	47,003,344	3.0
Industrial	9,095,123	8,905,346	2.1	36,560,333	35,744,949	2.3
Street & Highway	323,932	316,764	2.3	1,299,666	1,263,478	2.9
Other Public Authorities	714,728	720,130	(0.8)	2,877,826	2,705,325	6.4
Railroads	43,097	44,630	(3.4)	176,220	173,063	1.8
Interdepartmental	18,906	23,092	(18.1)	71,035	92,862	(23.5)
Total Revenues	34,952,622	35,129,202	(0.5)	147,926,967	143,694,135	2.9

Source: Edison Electric Institute, Statistics Department.

JANUARY-FEBRUARY 1993

ELECTRIC PERSPECTIVES

REWRITING THE RULES ON ENERGY

The Second Nuclear Era

A Look at Global Warming

The Cost of Compliance

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In the coming centuries, nuclear power will ensure global economic and social good, but not unless people now learn to weigh its real benefits and risks with those of other energy sources. To provide that perspective is the industry's imperative public-communication task.

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For some, the continuing emission of greenhouse gases portends disaster. The author, on the other hand, studies data that show cooler days, warmer nights, and better vegetables.

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Someone's cost is another's revenue—and in terms of the Clean Air Act Amendments, the emission-control industry seems to have the upper hand.

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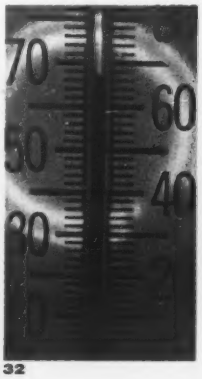

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PUBLISHER'S MESSAGE

As the magazine of Edison Electric Institute, the trade association of America's investor-owned electric utility companies, *Electric Perspectives* has a mission to put management issues in perspective for the industry's decisionmakers, regardless of their individual areas of expertise. That has been its goal since the first issue was published in 1976 and will remain so.

Nonetheless, exactly how it fulfills its mission has changed as necessary over the years to meet your needs best. For instance, 10 years ago *EP* was a black-and-white quarterly with a small paid circulation, which helped offset some of the magazine's production costs. No advertising was accepted. Now it is a four-color bimonthly available free to qualified member-company personnel as well as through paid subscriptions. Yet because advertisers recognize what a powerful audience you are, today *EP* pays its own way.

The new elements in this issue are simply the latest changes made to meet your needs better. They are the result of a readership survey we took last summer to learn more about who you are and how *EP* can serve you best. Here's some of what we found.

And the Survey Says...

First, 44 percent of you describe yourselves as mid-level managers. Twenty-three percent are division, plant, or general managers, and 10 percent are top-level executives. The typical reader is 48 years old and had a 1991 compensation package valued at $81,000. Most of you spend more than 30 minutes with each issue, and one fifth spend more than a hour. You share your copy with one or two colleagues, giving *EP* an estimated readership of 54,000 in investor-owned electric utilities.

Given your level of responsibility, we weren't surprised to learn that nearly all of you (83 percent) are actively involved in your companies' purchasing decisions. In 1991, for example, half of you who authorize such expenditures approved power production purchases of more than $18 million.

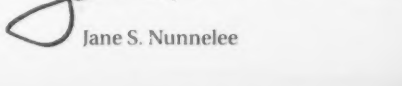
We were surprised, however, to learn what exclusive access we have to you: Of seven other well-known trade magazines that we asked about, not one reaches even half of you, and only two reach more than a quarter of you. In fact, 23 percent of you don't read any of the seven regularly, which makes it even more important that *Electric Perspectives* deliver what you need.

Meeting Demand

Hence the editorial and design changes making their debut with this issue. We took you at your word and added those items the survey said would most increase *EP*'s value: a list of feature topics on the cover, an industry news and trends department, a product section incorporating the technology review, and a column by guest editorialists. Together they increase *EP*'s flexibility, enabling us to bring you more news, analysis, and commentary in each issue.

With this issue, we've also moved to a lighter paper and eliminated the polybag in which *EP* used to be mailed; both changes offer environmental benefits while simultaneously reducing costs.

We sincerely hope you like what you see, and we welcome any comments or suggestions. If *Electric Perspectives* is to remain "the magazine for management in America's investor-owned electric utilities," we need to know what you think. So, write, call, share your ideas with us. The better we know you, the better we can deliver what you need.



Jane S. Nunnelee

ductive utility-owned electric power plants to prices paid to 1,500 different nonutility generators. In 1990, the average variable cost to utilities at the six plants was $0.02 per kWh for 119 megawatthours (MWh), yet the average price paid to IPPs was approximately $0.06 per kWh for 115 MWh.

For more information, contact the Utility Data Institute, 1700 K Street, N.W., Washington, DC 20006, 202/466-3660.

DUKE POWER HELPS OUT WITH DAYCARE

Over 40 percent of large U.S. investor-owned electric utilities offer some form of childcare resource and referral or consultation service for their employees according to a recent survey by The Partnership Group, a nationwide dependent care consulting firm.

And, although it wasn't among the 27 companies surveyed, Duke Power Company's particular program is notable. The utility's customer-service center is a recently centralized, 24-hour operation in University Research Park in Mecklenburg, North Carolina. The centralization and multishift character of the work would have put great strains on employees' family lives and certainly the company's staffing abilities and work atmosphere. It can be a hard row to hoe for a parent to make care arrangements for young children, make a long commute, and work an average day.

Duke, the Park's management company, and the other multishift organizations there—an IBM division, American Express Health Systems Group, and Allstate Insurance—put up $2 million to build a daycare center specifically for the children of the 19,000 employees in the industrial park. Duke's share was approximately $400,000, and in return the utility received a guaranteed number of spaces for its employees' kids. (The center was pictured in a sidebar on daycare in the September–October 1992 issue of *Electric Perspectives*.)

Managed by Bright Horizons, a company based in Cambridge, Massachusetts, the Park's new center can accommodate up to 180 children—infants to preschoolers.

YOUR FILL OF OYSTERS

Delmarva Power & Light produces approximately 300,000 tons of fly ash annually. To cut landfill costs, it plans to use 250,000 tons in different ways—mostly as a cement filler for road construction.

But the utility is also looking into constructing marine habitats. It seems that in an experimental Atlantic reef built by Delmarva in the 1980s in conjunction with the University of Delaware, oysters actually preferred (hands-down, as it were) the fly-ash structure to other bases. That could be an inexpensive aquacultural solution to the problem of recent low oyster harvests in the Chesapeake Bay.

MOVING TARGETS

Language can be subtle or a bludgeon, or both at once. In "Does 2+2=5?" (September–October 1992), Tom Flaherty provided a list of selected electric utility mergers and acquisitions, along with the premium-over-market price, net income, and book value. Each transaction noted the "acquiror" and the "target," without further explanation.

But a merger and an acquisition, however many times the two are mentioned in the same breath, aren't the same. An acquisition is direct—one company buys another—and the aggressive language of acquiror and target sounds apt. "Merger," however, connotes a agreement much more mutual than that, and so the language doesn't quite hit the right note. In fact, depending on the transaction's particular key, it may be totally off the scale.

In the case of the 1990 merger into one holding company of Iowa Resources, Inc. and Midwest Energy Company (to form Midwest Resources, Inc.), the parties went to great lengths to describe the transaction in mutually beneficial terms, which helped emphasize the mutual benefits for customers, shareholders, and employees alike. "We have worked very hard to find the equitable way to accomplish this as a 'merger of equals,' and we believe the agreement is unique in that respect," Russell Christiansen, the CEO of Midwest Energy, said at the time.

In the recent *Electric Perspectives* article, we listed one as the acquiror and the other as the target, and that mistakenly changed the spin.

MORE EDUCATION PARTNERSHIPS

Electric utilities have a solid history of education partnerships—Sierra Pacific's Homework Hotline is just one of the ways electric companies link up with area school districts. There are many other activities, involving everything from teacher training seminars to student grants to education resource materials:

Partnership	% of electric utilities with program
Youth organizations	70
Other utilities	68
School districts	60
Colleges/universities	59
Advisory council/panel	55
State education department	52
Local/state alliances	47
Other businesses	45
Government agencies	44
Adopt-a-school	44

Source: Edison Electric Institute

PATRICK J. MICHAELS

GLOBAL WARMING

Popular Vision vs. Scientific Fact

FOR SOME, THE CONTINUING EMISSION OF GREENHOUSE GASES PORTENDS DISASTER. THE AUTHOR, ON THE OTHER HAND, STUDIES DATA THAT SHOW COOLER DAYS, WARMER NIGHTS, AND BETTER VEGETABLES.

Frank Siteman / Unlimited

IN THE popular vision, environmental apocalypse looms over the land. It's a vision of catastrophic global warming that ultimately leads to crop failures, rapid and inundating surges in sea level, enormous hurricanes, and burning forests incapable of renewing themselves.

It's become warmer, yes, and perhaps will be warmer still, but to the degree of catastrophe? The available data on climatic change say no. It's true that virtually all scientists directly involved in climatological research (this author included) believe that the earth will warm some as a result of the increase in emissions that absorb infrared radiation or enhance the greenhouse effect. Indeed, though the media portray the debate otherwise, global warming is not a struggle between true believers and skeptics. The fact is that while the scientists who have examined the issue know that the planet has warmed slightly in the last century, few will ascribe much, if any, of that warming to a change in the greenhouse effect.

Further, warming itself does not imply the apocalypse that dominates the rhetoric of many environmentalists. In fact, within certain quite broad limits, how

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An increase in carbon dioxide in the atmosphere may be a fact, but the consequences for this farmer may be far from dismal.

Matthew McVay / Folio

FIGURE 1

NORTHERN HEMISPHERE GROUND-BASED TEMPERATURE TRENDS

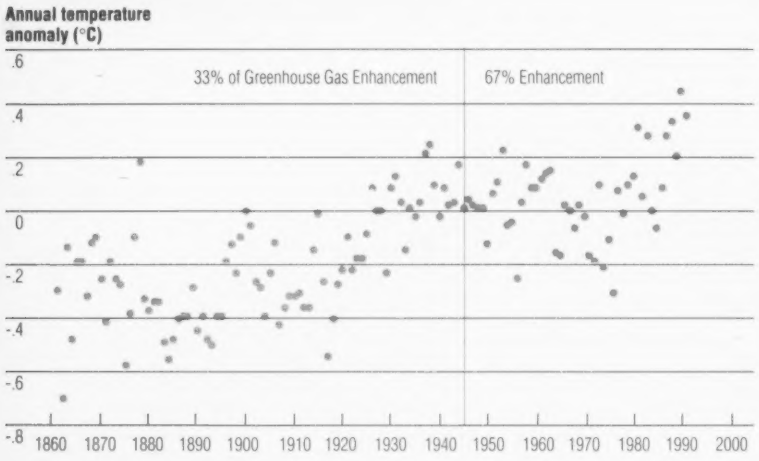


Figure 1: This record, from the University of East Anglia, is the one most cited by scientists. Two-thirds of the greenhouse enhancement took place to the right of the red line.

much the world warms is irrelevant. More important is *how* it warms—whether during the day or at night, whether in the winter more than in the summer, and whether such other factors as changes in cloud cover can modify that warming.

Once you know how it warms, the spectre of environmental disaster dims rapidly.

A Changing Greenhouse

The greenhouse effect is real and, indeed, a natural and beneficial phenomenon. It is a warming of the lower layers of the atmosphere resulting from the absorption of solar radiation by certain gases. Water vapor is the most common gas, followed by carbon dioxide, whose net effect is an order of magnitude less.

While there are several greenhouse-enhancing trace gases that have increased as a result of man's activities, four kinds are responsible for almost all the current increase in radiative forcing: carbon dioxide, methane, nitrous oxide, and chlorofluorocarbons. The enhancement and concentration of these gases in the lower atmosphere redirects toward the Earth's surface an increasing—although still extremely small—amount of solar energy.

Of these emissions, carbon dioxide, or CO_2, is the most important, producing approximately half of the overall greenhouse *enhancement* (that is to say, the enrichment of the "natural" greenhouse). It is also the emission that results from the combustion of fossil fuels—coal, oil, natural gas, and their fuel byproducts—with coal producing the largest amount per unit of energy released. Because coal combustion produces more than half of this nation's electricity, a serious attempt to stabilize greenhouse gases—requiring an 80 percent cut in emissions—would have serious and profound consequences for our energy economy.

Before the Industrial Revolution, CO_2 concentration was between 260 and 279 parts per million (ppm). The current atmospheric concentration of CO_2 is about 350 ppm, and if the warming influence of other greenhouse gases is translated into CO_2 terms, it's like adding another 80 ppm of CO_2, yielding a total *effective* concentration of approximately 430 ppm—up an additional 51–61 percent from the pre-industrial background range. Thus, we have already proceeded more than halfway to doubling CO_2 concentration in the atmosphere.

The Rise of the Popular Vision

Two events used this CO_2 rise to foster the popular fear of climate apocalypse. The first was the publication of data from general circulation model (GCM) climate simulations in the mid- to late 1980s. Factoring in an effective doubling of atmospheric CO_2 (which, at current emission rates, will occur around 2050), these computer models predicted a mean global warming of 4.2°C, with a winter increase of as much as 18°C in north polar regions.

The second was the Congressional testimony of NASA's James Hansen, a prominent environmental scientist, in the summer of 1988. He said that there was a "high degree of cause and effect" between current temperatures and human greenhouse alterations, but nowhere in his testimony (and, to my best knowledge, nowhere else) did he state that an enhanced greenhouse effect had caused the anomalously warm summer. Nevertheless, the press and the public concluded otherwise: 70 percent of the respondents to a subsequent CNN poll agreed with the statement that the 1988 drought was in fact caused by the greenhouse effect.

Facts vs. Popular Vision

But consider this. With a 61 percent increase in background CO_2, the current GCMs predict that the globe should have warmed considerably, especially in the high-latitude polar regions of the northern hemisphere. If something were not mitigating the warming, we should already have seen a rise of 2.0°C or so. Yet, according to United Nations figures, the historical trend is a rise of 0.45°C (±0.1°C) in the last century. Further, as shown in Figure 1, nearly all of the northern hemisphere's upward

Martin Rogers / Unphoto

Scientists don't dispute the existence of the greenhouse effect. The public, however, interprets it incorrectly, with the wrong rhetoric.

trend in temperature occurred prior to 1945, before the major postwar enhancement of the greenhouse effect. In fact, a linear trend through the data since 1935 is statistically indistinguishable from no change at all. Trend analyses of global records also indicate that almost all of the observed warming occurred prior to 1945—before most of the greenhouse emissions.

One reason for the lack of observed warming is the lag effect caused by the deep oceans—it takes more energy to heat up water than to heat up land, after all. Several calculations by different scientists, however, demonstrate that even large estimates of this lag are insufficient to account for the lack of observed warming.

Also, the temperature records themselves reflect an upward bias that can skew the data. Many weather stations are in cities, and cities tend to grow up around their central weather stations. Consequently, temperature readings are generally higher because the city is generally warmer, which has nothing to do with global or enhanced greenhouse warming.

Washington, DC, is a good example of this phenomenon. Temperatures in the Nation's Capitol have been skyrocketing since the 1920s (like the federal budget, some say). In fact, the mean January temperature measured at the urban Washington National Airport is now warmer than that measured at the Charlottesville (Virginia) Leander McCormick Observatory, 100 miles to the south! There are many uncertainties in the study of climatic change, but we are sure that Washington has not moved south. Rather, the urban landscape's infrastructure (containing pavement that retains heat and buildings that impede ventilating winds) is the main culprit.

In 1979, NASA launched the first of a series of satellites capable of measuring the temperature of the lower layer of the atmosphere with an accuracy of ±0.01°C. The satellite's coverage is virtually global, and there's no urban effect in these data. From the charted 1979–1992 data in Figure 2 (page 37), it is immediately apparent that there is no significant warming trend in either hemisphere. In addition, the fairly rapid warming between 1979 and now—which seems obvious in the ground-based record—is absent in the satellite data.

Figure 3 (page 37, part of a presentation to this January's annual meeting of the American Meteorological Society) compares the performance of our most sophisticated GCM with observed temperatures over the northern hemisphere. It is apparent that the forecasts began to fail in the middle of the century—just as the current greenhouse enhancement became most important.

In his book, *The Heated Debate* (Pacific Research Institute, 1992), Robert Balling convincingly demonstrates that observed warming of the planet has been far below even the most conservative projections of the GCMs. He also indicates that other industrial

GETTING TO MAYBE: CLIMATE SCIENCE OR POLITICAL SCIENCE?

By Robert Beck

In the 1970s, it was global cooling. In the 1990s, it's global warming. Which is accurate? Both and neither. Yes, your eyes read correctly. Both statements have scientific data to support them and yet another set of data to refute them. Is it any wonder that policymakers are confused? What role can—and should—science play when the data do not support a clear policy choice?

Funding drives science and scientific research. Computers, the time to run them, laboratory equipment, and the drive for fame have driven the cost of research to an all-time high. The old axiom "publish or perish" has never been more true, this at a time when both academic and federal research budgets are shrinking. Competition is intense, and headline-making findings are a major tactic to ensure funding.

Is that tactic wrong? In the purely ethical sense, yes. But if a project or laboratory or department is not successful in winning the support it needs, how can it undertake the research necessary to advance scientific knowledge? Thus, the more practical answer to the question is, probably no. The challenge for policymakers is to let the funding rhetoric go by and pick out the facts they need to make fair public policy.

To do this, policymakers need to ask scientists the right questions and then insist that the answers be the best they can be with the data at hand. Too often, policymakers ask the wrong questions or often no questions at all. They allow the scientists to frame the questions they want to answer, even though the questions have no value to decisionmakers. The global climate change issue is rife with such examples. Refer, if you will, to the first two sentences of this sidebar. Within two decades, the same scientists, going back more than 150 years over the same historical climate records, reached completely opposite conclusions. Why? Primarily because the political climate changed.

During the 1970s, the first Decade of the Environment, politicians focused on basic environmental protection of air and water. Many laws went into the books, and by the passage in 1990 of the most sweeping legislation—the Clean Air Act Amendments—the targets for conventional environmental protection were all but exhausted. Climate science was a low priority for policymakers then, but now, in the current Decade of the Environment, it's been called up to the major leagues.

And the stakes have risen, too. What used to be minor congressional hearings held in small, fourth-floor hearing rooms, attended by a few professors and one or two legislators, are now in the main committee room covered by C-SPAN and CNN: Political posturing and debate one-upmanship are the order of the day. The audience wants to know: Is warming occurring or not? Will New York, Miami, and New Orleans flood or not? No time for long, scientific dissertations on maybe answers—it's yes or no. And if it's no, it's back to the fourth floor, and the lights go out, and the cameras go home. If it's yes, interviews and headlines abound. Better still, if the answer is no *and* yes, then we have controversy, another hearing, and more research on both sides—a true "win-win" for those involved.

But is this good for science? Is it the best way to use science in the policymaking process?

Sometimes yes, most times no, but almost always, it is painfully slow and very expensive.

There is room for improvement on both sides. Policymakers must learn to ask the right questions to obtain the information they need to establish sound environmental policy. Scientists and researchers must answer those questions honestly. Those on opposite sides of an issue must stop presenting their own side as 100 percent correct while portraying the other side as environmentally radical or criminal.

Also, we must change the idea that because 300 scientists support side A and only 25 scientists support side B, side A must be correct. Elections may work that way, but the physical world does not. Neither scientific nor political opinion is always an accurate indicator of truth.

What matters here is not who's right but what's right. A more objective and less polarized debate would surely help us discover the answers sooner.

Bob Beck is vice president of environmental affairs for the Edison Electric Institute.

byproducts (such as sulfate aerosol, associated with acid rain) are largely responsible for this lack of warming. Several calculations (those of NASA's James Hansen, for example) indicate that the magnitude of compensatory cooling could be sufficient to have canceled all of the expected greenhouse warming to date.

In my opinion, however, the observed data on global climatic change demonstrate that the sulfate cooling hypothesis is insufficient. In fact, there is evidence for a concurrent increase in cloudiness that is not related to this aerosol, but rather is a result of the greenhouse enhancement itself. Enhanced cloudiness reflects solar radiation during the day and insulates the planet at night. The importance of increasing cloudiness in a world with an enhanced greenhouse effect cannot be overstated, for it spells the demise of the popular vision of apocalypse.

Send in the Clouds

In the popular vision, global warming has three major threats:

- agricultural damage from major reductions in crop yields;
- disastrous sea-level rise from the melting of large areas of land ice; and
- ecological disequilibrium and loss of species because climate will change faster than parent plant communities can migrate.

Each of these threats are diametrically attenuated in the face of a greenhouse enhancement that is mitigated by clouds.

The primary cause of agricultural yield loss is moisture stress and plant death from lack of water. Plant stress is at its highest generally during the day, especially on sunny, hot afternoons.

FIGURE 2

TEMPERATURE RECORDS FROM SATELLITES

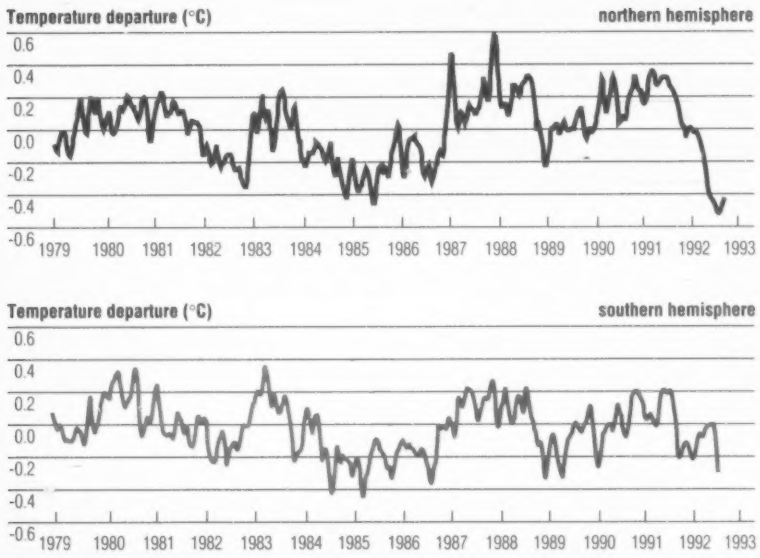
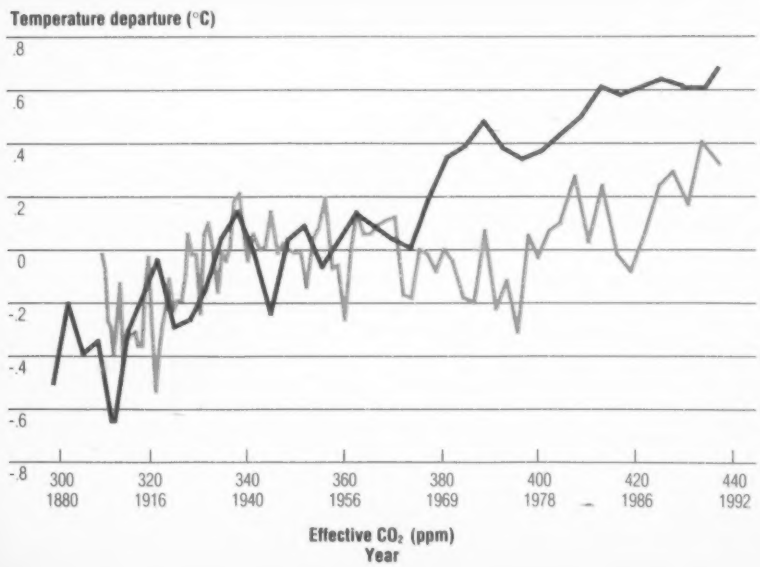


FIGURE 3

GCM PREDICTIONS vs. OBSERVED TEMPERATURES



An increase in cloudiness will block the sun and mitigate daytime temperature rises, thereby reducing the stress. Also, temperatures at night generally mark the beginning and end of the growing season—and the lowest temperatures at season's end occur at the end of clear, calm nights. Warming these nights, or affecting the conditions under which cold air masses form, will therefore lengthen the growing season.

Large areas of high-latitude land ice—which must melt in order to create a significant sea-level rise—melt during summer. Yet all climate models, from the 1896 calculations of Savante Arrhenius (who wrote the first greenhouse warming study) to the most recent Princeton GCM (demonstrated in Figure 3), confine their strongest warming to high-latitude winter, which is spent in darkness or twilight. Further, by modifying the projected warming with an increase in cloudiness, we could cancel out entirely the warming in high-latitude summer. This is precisely what occurs in the most recent publication of the National Center for Atmospheric Research (NCAR) GCM: In the world of doubled CO_2, it forecasts not summer warming but actual cooling in many portions of the northern hemisphere's high latitudes!

The winter atmosphere—which contributes most to high-latitude snowpack accumulation—is now so cold that very little moisture can precipitate. By warming the winter, the amount of moisture and snowfall should increase—and then, under any warming scenario, the temperatures would still remain far below freezing.

In fact, snowfall apparently increased during the last warm period, from 4,000 to 7,000 years ago, according to 1991 studies by Eugene Domack et al. in the journal *Geology* and Gifford Miller and Anne de Vernal in *Nature* in

Figure 3: Northern hemisphere observed temperatures (green line)and temperatures calculated for the last 100 years by the most sophisticated climate model (blue line).

Robert Rathe / Folio

Studies show that clouds are on the increase, providing ecological benefit, not disaster.

1992. These papers both argued that warming would actually increase the ice volume, further mitigating any rise in sea-level.

The third negative prospect from climatic change—ecological disequilibrium—also weakens in the face of a cloud-mitigated greenhouse. The primary cause of plant death, as I've said before, remains moisture stress, which is primarily generated during the day. In addition, Lehman and Keigwin, in a 1992 *Nature* article, found that temperature changes of 5°C in fewer than 50 years—values that exceed those of current GCM projections—have been common in the last glacial cycle. These observed climatic changes, more rapid than those forecasted, were obviously insufficient to promote an ecological disaster.

Are there really more clouds? There's good, direct evidence that clouds are on the increase. James Angell of the National Oceanic and Atmospheric Administration (NOAA) has demonstrated that cloudiness has increased by 3.5 percent across the United States during the period of major greenhouse enhancement. In Europe, German scientist Gerd Weber has noted a decline in sunshine also caused by increasing cloudiness. And Steven Warren, of the University of Washington, has analyzed millions of shipboard observations (which generally are recorded every three hours) and found global cloud increases, especially in the northern hemisphere.

The circumstantial evidence is equally compelling. Increasing cloudiness from any source—including sulfates—should have a number of hypothetical effects:

- night warming, especially enhanced by an increasing greenhouse effect;
- counteraction of day warming;
- a consequent decrease in the difference between daily high and low temperatures;
- the greatest warming should be on the longest (winter) nights; and
- the greatest counteraction of warming—even cooling—should occur on the longest (summer) days.

And, in fact, the observed data support each of these effects.

Thomas Karl, laboratory director at the National Climatic Data Center, has created a "Historical Climate Network" (HCN) for the United States. He scrupulously avoids data that would reflect warming caused by cities. In his

record, daily high temperatures have actually declined for most of the last 70 years, while night readings have risen since 1945. The difference between the high and low, shown in Figure 4, has been narrowing for the last three decades.

Karl also has created an HCN-like record for China and the former Soviet Union. I combined those results with the northern hemisphere's in the October 1992 *Bulletin of the American Meteorological Society* and divided them into day, night, winter, and summer. As is shown in the Table 1, it is apparent that summer daytime temperatures—the ones that must rise to give credence to disastrous global warming scenarios—have actually dropped.

Instead, there has been a dramatic rise in the winter night temperatures. When we search the climate record to pinpoint when and where this has occurred, it is apparent that the fabled Siberian Express--the coldest air masses into our hemisphere—has warmed up. The Express is the same air mass responsible for the death of citrus in Florida and massive consumption of energy for heating in winter.

Sulfate aerosol or greenhouse effect? As benign as these climatic changes are, the question of causation remains. Are they the result of a modification of the greenhouse effect by sulfate aerosol? If so, this is tantamount to treating an environmental situation with a deleterious cure: The precipitation of the aerosol is, after all, acid rain (although the perceived magnitude of that problem has declined dramatically in the last decade).

If, on the other hand, the observed (and fairly pleasant) climatic changes are by and large the result of the greenhouse effect, then we should be able to observe two additional phenomena:

- night, day, and seasonal changes at high-elevation land stations (such as mountaintops) should be similar in character to those observed at low elevations; and
- there should not be disproportionate night warming in the southern hemisphere, because its clean atmosphere contains little sulfate aerosol.

Theoretical calculations all agree that surface warming should be accompanied by some cooling of the upper layers, although most GCMs confine this cooling to regions above the earth's active weather zone (approximately 45,000 feet in the mid-latitudes). But NOAA's James Angell has demonstrated that cooling has been observed from approximately 25,000 feet and up, easily within the active weather zone. Everything else being equal, this should result in increased vertical motion of air masses and a propensity for increased cloudiness. Thus, the response to the greenhouse enhancement may be to increase mid- and high-level cloudiness.

Almost all sulfate aerosol is confined—along with other particulates—to the bottom 7,000 feet of the atmosphere. If the cloud increases were primarily a result of this process, then high-elevation stations should not show the night warming and counteraction of daytime warming that we see in low-elevation records.

Figure 5 details maximum (day) and minimum (night) temperatures for winter and summer from the Pic du Midi Observatory in the French Pyrenees. Data from this station are particularly significant. The terrain

TABLE 1

TEMPERATURE TRENDS
USA, Continental China, and the Former Soviet Union

Area-weighted aggregate, °C/100 years

Season	Mean Max (day)	Mean Min (night)
Winter	+0.6	+1.8
Summer	-0.4	+0.4
Annual	+0.05	+1.1

FIGURE 4

AVERAGE DAILY TEMPERATURE RANGE
(Areally weighted, urbanized adjusted)

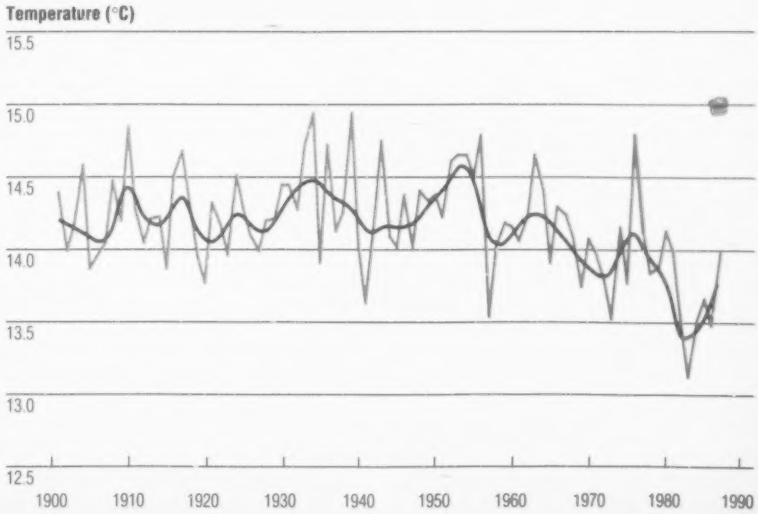
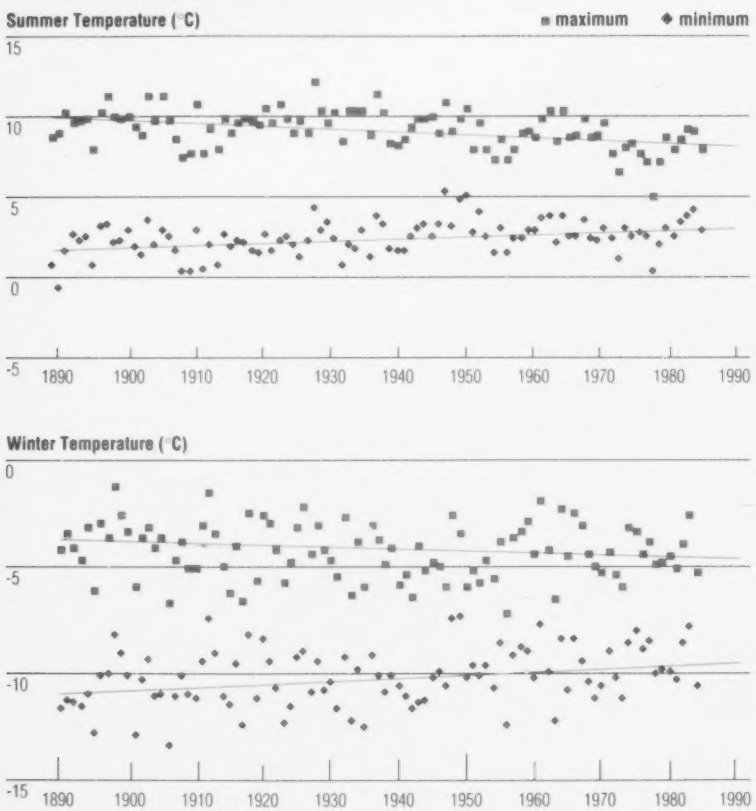


Figure 4: Karl's Historical Climate Network demonstrates the difference between average daily maximum (day) and minimum (night) temperatures since 1900. That difference (blue line) has been narrowing.

FIGURE 5

DAILY MAXIMUM AND MINIMUM TEMPERATURES AT PIC DU MIDI



surrounding it is exceedingly difficult to navigate, which minimizes human interference; and it is above the timberline, so that growing trees cannot artificially warm the nights or cool the days. Perhaps most important, at 9,400 feet, it is above almost all of the sulfate aerosol.

Yet, its behavior is similar to that of the aggregate of low elevation stations detailed in the table. The rise in night temperatures (both for summer and winter) is highly significant, as is the decline in summer day temperature. The magnitude of these changes is clearly out of proportion with the miniscule amount of sulfate aerosol residing at or above 9,400 feet. Thus, we're left with the other cloud-enhancement mechanism—namely, the high-altitude cooling noted by Angell.

P.A. Jones, writing in *Australian Meteorological Magazine* in 1991, demonstrated that night warming in Australia also exceeded day warming, in this case by a factor of two (0.12°C vs. 0.06C° per decade). The aggregate warming is still below projections made by GCM simulations. Interestingly, Steven Warren's cloud studies around Australia show increases in cirrus (high-altitude) clouds, but no concomitant increase in the low-level stratocumulus, which is the type one would expect to be enhanced by sulfate aerosol.

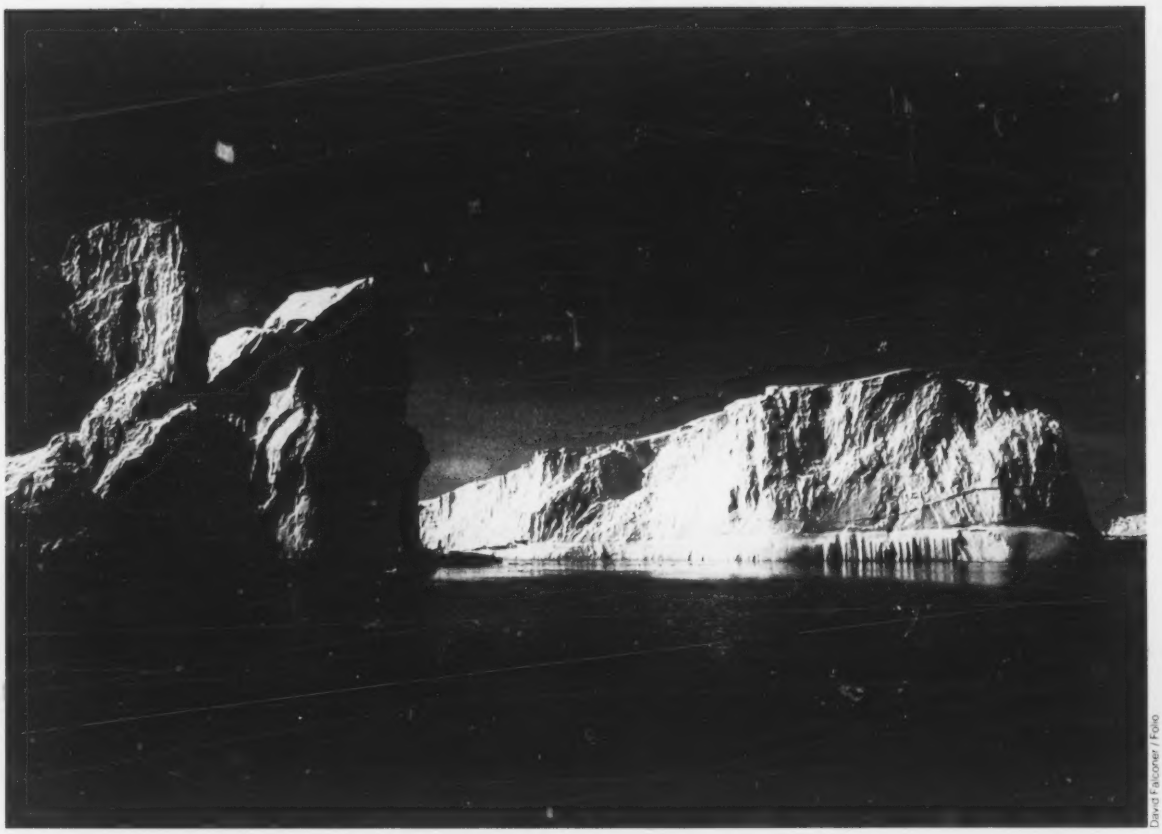
New Climate Models

As noted above, earlier climate models predicted an average warming of 4.2°C for an effective doubling of atmospheric CO_2, which is to occur around 2050. Those models—which included very primitive ocean and cloud specifications—have since been improved, and there have been some important changes.

The United Kingdom GCM, for example, changed the distribution of water and ice within clouds, and its projected mean warming dropped from 5.2°C to 1.9°C. With an improved understanding of the relationship between ocean and atmosphere, the NCAR model showed that warming dropped to 1.6°C for 30 years after an "instantaneous" doubling of CO_2, compared to 3.7°C in an earlier calculation for total warming with a more primitive ocean. A slightly different version of this model, in which the greenhouse effect increases at a rate commensurate with industrial emissions, implies that the global temperature should have risen by 0.7°C since 1950; the measured trend is less than half—0.33°C—of what was projected.

The Princeton GCM still predicts a net equilibrium warming of 4.0°C in its improved version—but as we saw in Figure 4, the observed data don't bear the model out.

Even though these new simulations appear to be too warm, they still predict most warming in high-latitude winter of the northern hemisphere. In the new version of the NCAR model, the area of projected warming of greater than 4°C is less than 5 percent of the planetary surface. More important, because almost all of it is confined to latitudes higher than 60° (just below the Arctic Circle) during the northern hemisphere's winter, the strong warming is therefore projected for either twilight or night, similar to what has been observed in the climate record. Note that these calculations are



David Falconer / Folio

An increase in winter temperature increases snowfall, insulating the frozen snowpack.

made without the addition of compensatory cooling by sulfate aerosol.

Benefits of CO_2

For a long time, we've known that many plants display enhanced growth in the presence of increased CO_2. This shouldn't be surprising to those who learned basic biology: CO_2 is the prime reactant in the familiar equation of photosynthesis. In a recent multi-subject analysis of the scientific literature, Keith Idso documented 1,087 individual experiments detailed in 324 scientific papers. With an increase in the CO_2 content of the air, 93 percent of the plants showed an increase in productivity, while only 2 percent showed a decrease.

And if, as we saw earlier, the growing season lengthens, so too will the time in which deciduous plants can capture CO_2.

Several real-world surveys indicate an acceleration in vegetative growth. Writing in *Science* magazine in 1992, Pekka Kauppi has demonstrated that European forests have increased in biomass over the last two decades. It's his belief that "the fertilization effect of pollutants override the adverse effects, at least for the time being." According to Sherwood Idso, the effect has been noted in montane species in the western United States, in a carefully monitored virgin forest plot at the Oak Ridge National Laboratory, and in the northern forests of Scandinavia.

If these accelerations are indeed taking place, they are occurring at a time when acid precipitation ostensibly is retarding forest growth. If sulfate aerosol is one (albeit insufficient) factor involved in mitigating prospective warming, then its negative effects (acid rain) are being countered, in part, by enhanced CO_2. An additional factor of environmental importance is that enhanced cloudiness—whether caused by sulfate aerosol or upper cooling from the heightened greenhouse effect—serves to block incoming solar radiation, mitigating effects of a stratospheric ozone decline. This combination of factors is probably responsible for the findings detailed in *Science* and *Geophysical Research Letters* that surface u-vb radiation—the causal agent for basal-cell skin cancer—is actually declining across the United States and much of the northern hemisphere.

Well, What Apocalypse?

That decline in the radiation flux that causes cancer adds weight to the other factors that create doubt about the popular vision, even in the face of an effective doubling of CO_2 in the atmosphere. In fact, the actual lack of data pointing to overall warming, the prevalence of what warming there is during the night and winter rather than on summer days, the new evidence from improved GCMs, and the evidence for enhanced vegetative growth all suggest one thing.

The popular vision of climate apocalypse is wrong. ◆

BY BRUCE H. BRAINE

CONFRONTING THE COST OF COMPLIANCE

TO COMPLY with the Clean Air Act Amendments (the "Amendments") of 1990, electric utilities will certainly incur significant costs, borne ultimately by the electricity customer and the utility stockholder. While that compliance burden is heavy for many utilities, there are ways to take aggressive advantage of the current competitive nature of the emission-control market, as well as some of the regulatory alternatives included in the Amendments. It's one of the main ways utilities can reduce compliance costs and improve their own competitive position.

Of course, that's easy for *me* to say—my job is to describe options and to coach the utility once it has chosen its direction and schedule and jumped into the compliance water. But I'm well aware that I'm not the one who's jumping, the one who ultimately bears the risk of the aggressive decision. An electric utility can decide to jump in—or make its decision after it sees how others fare once they jump in. If it weren't such a broad economic question, the dilemma would be nearly existentialist. Each utility has a unique blend of considerations, its own decision tree concerning its customer base, fuel mix, state commission, state regulations, financials, and bond ratings, among dozens of other issues. Its decision to jump or to observe is weighty and complicated by deadlines and the real risk of failing. And regulatory treatment by public utility commissions, changes in market conditions, and future environmental regulations may affect *all* utilities' ability to contain their cost increases. So far be it from me to stand away from the shore and claim cheerily that the water is fine.

But still and all, I want to point out the options, whether they're universal or not: Whatever risk those changes bring could well be worth taking, particularly if the potential cost advantage is significant.

ICF Resources estimates that under Title IV (acid rain) alone, annual electric utility costs will increase by up to $3 billion dollars per year by 2000 due to the sulfur dioxide (SO_2) and nitrogen oxide (NO_x) reduction requirements. Significant amounts of capital will go to flue-gas desulfurization technology (i.e., scrubbers), low-NO_x burner technologies, continuous emission monitors, and boiler and particulate control upgrade and replacement necessitated by shifts to lower-sulfur coals. In addition, utilities might have to invest substantially in other emission-control

SOMEONE'S COST IS ANOTHER'S REVENUE—AND IN TERMS OF THE CLEAN AIR ACT AMENDMENTS, THE EMISSION-CONTROL INDUSTRY SEEMS TO HAVE THE UPPER HAND.

Bruce Braine is a vice president of ICF Resources, Inc. (Fairfax, VA). He bases this article on an August 1992 report that ICF Resources and Smith Barney prepared for the Environmental Protection Agency (EPA): "Business Opportunities of the New Clean Air Act: The Impact of the CAAA of 1990 on the Air Pollution Control Industry." The report presents findings from ICF Resources and Smith Barney research, as well as a compilation of results from a wide range of already completed, publicly available studies.

Just one example: To meet Phase I requirements, Public Service Electric & Gas will spend $430 million to repower its 33-year-old Bergen Generating Station. **The new gas-fired combined cycle system will effectively remove most NO_x and SO_2** and add 570 **megawatts of capacity.**

A CONCRETE EXAMPLE

By Eric R. Blume, associate editor

Just beyond the entrance to Allegheny Power System's Harrison Power Station in Shinnston, West Virginia, it's a like a trailer park. Mobile offices for construction companies line the right side of the road, and they seem as if they've been there for years. Further down the line, construction workers move purposefully, and we're told to remember that it is an active hard-hat area. All these people belong to companies subcontracted by United Engineers & Constructors, which Allegheny Power signed on as the main contractor for—and now you can see it to the left, big boots, heavy trucks, gawky backhoes, towering cranes, and oceans of concrete—the largest current construction project in North America.

It's Allegheny's $726 million Harrison Power Station magnesium-enhanced flue-gas desulfurization system going up . . . a scrubber.

"Scrubber" diminishes the reality—you're not talking about a bottle-brush or a simple smokestack filter. It is a massive project, whose goal is to reduce SO_2 emissions by 98 percent. And that requires a huge multistage process—from gas absorption to waste disposal—and structures covering virtually the same amount of ground as the generating plant itself:

- 2 lime storage silos, each 116 feet in diameter, which store enough lime to feed the system's 13,000-ton-per-week appetite (their construction involved the largest North American continuous concrete pour to date);
- a 1,000-foot chimney, housing an absorber at its 112-foot-diameter base, where a water-and-lime mixture (containing some magnesium) is sprayed into the boiler flue gas, mixes with SO_2, and precipitates to the bottom where it mixes with more lime to become a muddy solid—calcium sulfate;
- 4 200-foot-diameter thickener tanks, which receive the mud, take off water that rises to the top, and recycle it to the absorber;
- 15 centrifuges, which take the thickened slurry from the bottom of the tanks and remove even more water;
- a waste-processing building and three fly-ash silos, where the centrifuge "cake" mixes with fly-ash and yet more lime to become solid waste—a substance that in fact has use as gypsum—which is carted away by truck.

Courtesy: Allegheny Power System

That's not counting the new lime-unloading rail spur, the lime-unloading building, or the project's other supporting structures.

The three utilities that make up Allegheny Power System—Potomac Edison, Monongahela Power, and West Penn Power—will use the Harrison scrubber to meet *all* their SO_2 reduction requirements for Phase I compliance. The scrubber removes 64 tons of SO_2 per hour (which comes to more than 555,000 tons per year), and that—plus $200 million in low-$NO_x$ burners and continuous emissions monitors at other plants—is enough to cover the combined service areas.

But the deadline for Phase II of the Amendments looms as well. Allegheny Power's preliminary plans call for scrubbing the company's Hatfield's Ferry Station near Masontown, Pennsylvania, at a cost of $800 million.

The numbers are staggering, and so is the construction site. You leave it with a greater appreciation of the physical effort it takes to install a compliance strategy—and the enormous financial decisions a utility makes.

technologies—for example, selective catalytic reduction under the ozone nonattainment (smog) requirements of Title I, or new particulate control equipment, scrubbers, or even carbon absorbers under the air toxics provisions of Title III.

Logically, while many industries will incur compliance costs, significant growth in revenues and profits will belong to emission-control equipment manufacturers, engineering, design, and construction firms, and companies that produce or transport cleaner burning fuels. Between 1992 and 2000, Title IV of the Amendments will increase the revenues of emission-control equipment and clean-fuels suppliers by up to $21 billion cumulatively. About one half of that (approximately $7 billion to $11 billion) will go to low-sulfur coal producers and railroads. Most of the remainder will accrue to the emission-control equipment markets, primarily designers and manufacturers of scrubber and low-NO_x burner technologies. Boiler and particulate control equipment suppliers will benefit also, as utilities upgrade or replace boilers and electrostatic precipitators.

Notwithstanding these projected increases, the market structures for low-sulfur coal and natural gas, as well as for emission-control equipment, will undergo fundamental changes. In general, these markets have become very competitive—they have a relatively large number of companies with low profit margins. Prices have declined, reflecting technology advancements, overall productivity improvements, and (particularly with natural gas) government deregulation.

While the Amendments should re-

Powder River Basin coal can be an option for many utilities. One of the determining factors to consider is rail delivery price.

sult in expanded profits in certain markets with high near-term demand (for low-NO_x burner technology installed prior to 1995, for example), the experience in the scrubber markets is more typical. Inflated expectations of a 25–30 gigawatt scrubber market in Phase I (based on some initial engineering firm estimates) have given way to a more reasonable—and competitive—13 gigawatt market in Phase I. Further, the Amendments' SO_2 allowance system and NO_x averaging provisions ought to enhance competition among varying types of coal, natural gas, and emission-control technologies.

Because many power-plant units are not required to control emissions until 2000 (in Phase II), some utilities may not have fully considered their alternative emission control strategies. In fact, only a few of those affected in Phase II have identified all near-term options. This is certainly understandable from an environmental compliance standpoint, but perhaps not from a business standpoint. Some strategies require relatively prompt action. Opportunities to control escalating compliance costs—by taking full advantage of the emerging allowance market, by considering fuel switches and modifications, by developing new technologies, or by gaining improved regulatory treatment for conservation and demand-side management—are likely to be relatively short-lived.

It's time for those utilities to start their compliance portfolios.

Buy! Buy! Sell! Sell!

The fact that no SO_2 allowance trades occurred in 1991 worried some, but recent activity has strengthened the market's viability. In 1992, Wisconsin Power and Light's modest sales of 25,000 allowances resulted in cash payments of about $6.5 million. Alcoa sold 25,000 allowances at a comparable rate, and more trades are in the pipeline. In addition, the Commodities Future Trading Commission approved the Chicago Board of Trade (CBOT) proposal for a futures and cash market for SO_2 allowances; trading is scheduled to begin this spring. The EPA lottery (administered by CBOT) of a limited number of SO_2 allowances begins in March.

SO_2 allowances—each one bearing the right to emit one ton of SO_2—are a homogeneous "commodity" with no physical barriers to delivery (similar to a financial security) and, by Phase II, are allocated to virtually all electric utilities. According to an ICF Resources multiclient allowance study and earlier market analyses, the value of interstate utility trading could exceed $1 billion

Jim McNee / Unphoto

Many consider natural gas to be the winner in the Amendments, but the benefits for that market won't appear until the late 1990s.

annually during Phase II. Given the flexibility of spot sales, intrastate utility trades, and allowances that pass hands several times a year, trading could be several times that amount. CBOT has estimated that annual allowance trading will range from $5 billion to $10 billion a year—about the annual trading for wheat.

EPA released its final SO_2 and NO_x rules in November, and the IRS released some rulings on allowance tax treatements. Depending on how utilities view those rulings, it may take a longer time for them to lose their reluctance to trade and for the markets to take root.

Nonetheless, the recent transactions had reported prices of $250–$400 per ton—and that's a range that could provide some utilities with a unique market opportunity. Despite the falling price expectations over the last two years, these prices are probably still higher than the long-run value of allowances. In addition, future environmental legislation (on global climate change, for example) or changes in regulations (controls over SO_2 and NO_x near national parks, for example) drive up risks of low allowance prices. Selling allowances at current prices may be a timely strategy.

Many utilities can offset costs with allowance transactions today:

- *Buying time.* Of course, a number can purchase allowances in lieu of other costly compliance options. Some utilities in the southeast, for example, are likely to have internal marginal compliance costs approaching or above $1,000 per ton. Why? Allowances are allocated based on the average levels of fossil operation from 1985 to 1987, during which many southeastern utilities operated coal-fired units at relatively low levels as a matter of course. As electricity growth increases, however, these units will see more action—and the utilities, therefore, will work even harder to keep their average emission rates low during Phase II in order to comply. Some might even need to install scrubbers for *low*-sulfur coal.
- *Taking advantage of surplus.* A number of western and a few eastern utilities have more allowances than their current or likely future emission levels—even before they make further reductions. In general, these utilities have shifted to natural gas since 1985 because of lower costs or very stringent environmental requirements (as in California). Selling their surplus allowances can help offset costs: The estimated 300,000–400,000 annual surplus allowances over the first 10 years of Phase II could generate (at current allowance prices) more than $1 billion in revenues.
- *Creating allowances by going from oil to gas.* Some utilities can switch from oil-fired to gas-fired generation at a low cost (even a cost savings, in some cases), thereby generating extra allowances for sale. According to its integrated resource plan, Consolidated Edison plans to pursue this strategy. The Long Island Lighting Company has made a similar proposal.
- *Generating allowances by substitution.* The Phase I substitution regulations also provide a mechanism to reduce net compliance costs. They permit utilities to create allowances (beginning in 1995) at units not affected until 2000. The substitute unit receives allowances based on its 1985 SO_2 rate multiplied by "baseline" fuel consumption. In effect, the utility can generate allowance revenues at a low cost. To the extent that gas costs are cheaper than oil or low-sulfur western coal and gas displaces more expensive high-sulfur midwestern coal, there may even be a cost savings.

In short, utilities can sell allowances and increase revenues, or buy allowances and reduce compliance costs. Further, depending on the ultimate tax and regulatory treatments, allowance revenues could finance scrubbers or other emission-control measures.

But the opportunities to sell allowances at current market prices will be short-lived. Also, the extent to which one can take advantage of substitution plans will decrease over time.

The Low-Sulfur Coal Market

The coal market—for low-sulfur coal, in particular—has gone through many changes in the past several years. During the 1980s, underground coal-mine productivity increased annually at 7 percent per year, even though the growth in coal demand slowed. Average U.S. coal prices, measured at the mine, decreased by about 30 percent. Prices for low-sulfur coal from central Appalachia declined by an even greater percentage, with spot mine-mouth prices for low-sulfur compliance coals—which produce 1.2 pounds of SO_2 for each million British thermal units (MMBtu)—listing at about $23–$25 per ton today.

Even since the passage of the Amendments, low-sulfur coal prices have remained low. Relatively slack demand and competition from western sources (actively considered by utilities as far east as Georgia and New York) have contributed to the depressed prices. Although increased demand should result in some market tightening, ICF Resources contends, competition will be the force to hold down price increases. Further, western railroads, even with greater demands placed on them, likely will not suffer transportation bottlenecks—consider the fact that the major western railroads (Burlington Northern, Chicago North Western, and Union Pacific) plan to make more than $400 million in system investments.

Many utilities have examined the options of using lower-sulfur coal in boilers not originally designed to burn it. For their units designed to burn midwestern or even eastern higher-sulfur coals, utilities have focused particularly on western, subbituminous coals from the Powder River Basin (PRB) of Wyoming and Montana. This option not only provides a way to reduce compliance costs but also (in some cases) could yield net cost savings relative to current coal costs.

Using PRB coal in boilers designed to burn only bituminous coals will generally reduce unit performance and efficiency—low-sulphur coals have lower Btu content and higher moisture. That means more coal volume to produce energy—and therefore the unit often requires greater pulverizer and fan capacity to burn the coal. In addition, coal-handling procedures and equipment could also require modifications.

Utilities have widely considered PRB coal strategies only since 1990, primarily because of those technical concerns. The early engineering studies, too, were conservative regarding the effects of using western low-sulfur coal. Compounding the issue is the fact that during the late 1970s and 80s, many utilities signed long-term coal

TABLE 1

ECONOMIC COST OF A 10 PERCENT DERATE AT A 500 MW COAL UNIT
(Assuming Immediate Replacement Capacity Built)

Capital Cost (50 MW x 500 $/KW)*	$25 Million
Annual Capital Charges	$2.5 Million/year
Fuel Consumed (@ 65% Capacity Factor)	30 Trillion Btu
Cost of Derate	$0.08/MMBtu equivalent

*Cost of replacement capacity

Source: ICF Resources, Inc.

TABLE 2

AVERAGE DELIVERED 1991 SPOT PRICES FOR POWDER RIVER BASIN COAL TO MIDWESTERN PLANTS

Utility	Plant	$/Ton	¢/MMBtu
Kansas City Power & Light	Lacygne	13.78	80.87
Iowa Public Service Company	Neal	12.81	76.27
Iowa Power	Council Bluffs	11.90	71.67
Union Electric Company	Labadie	15.12	87.43
Wisconsin Public Service Company	Weston	19.79	112.86
Illinois Power Company	Havana	21.74	129.61
Illinois Power Company	Baldwin	21.29	121.84
Electric Energy, Inc.	Joppa	14.92	87.85
Northern Indiana Public Service	Michigan City	18.40	108.40
Indiana Michigan Electric	Rockport	18.81	110.48
Indiana Kentucky Electric	Clifty Creek	23.47	132.70
Tennessee Valley Authority	Paradise	19.17	113.14
Consumers Power Company	Cobb	22.19	125.90
Detroit Edison Company	Monroe	17.52	102.51
Ohio Edison Company	Burger	22.77	132.84

Source: FERC Form 423, ICF Resources, Inc.

contracts to mitigate price volatility and supply risks. As a result, some midwestern coal-fired plants are subject to high-sulfur coal contracts and have limited ability to reopen or terminate them. The Amendments have provided the impetus to look more closely at the low-sulfur subbituminous option; in some cases, through force majeure clauses or contract reopeners, they allow a utility to shift to these coals from present contracts.

Some midwestern utilities (Union Electric, Illinois Power, Northern Indiana Public Service, PSI Energy, TVA, and Ohio Edison among them) have tested PRB coals (either wholly or in blends) at boilers designed to use bituminous coals. In general, their results indicate lower capital costs or powerplant capacity derates than those estimated in the engineering studies. For example, while many earlier studies predicted derates of 15–20 percent or more for burning pure PRB coals, actual testing at TVA's Gallatin plant suggested an average derate of about 10 percent; and tests at other utilities show even smaller percentages. Even a 10 percent derate, while significant, still amounts to only about $0.08 per MMBtu equivalent fuel cost, as illustrated by Table 1.

Also, the combination of low relative mine-mouth PRB prices (about $4 per ton at the mine compared to $18–20 for midwestern high-sulfur coals) and competitive transportation rates offered by the railroads (two are vying for the business) has resulted in very competitive delivered prices. In fact, even without its low-sulfur characteristics, PRB coal can be inexpensive in comparison to high-sulfur midwestern coals. Spot prices of PRB coals (see Table 2) for a number of midwestern plants generally range from $0.72 to $1.33 per MMBtu, as compared with delivered high-sulfur coal prices of about $1 to $1.20 per MMBtu.

Finally, tests of PRB coals indicate that burning them could result in lower NO_x emissions. This factor could help offset the costs of meeting the NO_x limits under the Amendments.

Other lower-sulfur options—coals originating from Colorado and Utah as well as central Appalachia—have been available at very competitive prices to date, and many midwest utilities have relatively good access to them, assuring a low-cost compliance option. The combination of these options provides utilities with unique opportunities for leverage on their current high-sulfur coal contracts as well as on renegotiating above-market contracts. Because the Amendments could lead to the termination or renegotiation of many higher-priced contracts and have led to the consideration of other coal sources, plants that are currently captive to specific railroads can even use this leverage to renegotiate their rail contracts as well. Other future options notwithstanding, utilities could reduce their use of these higher-cost plants or buy allowances to avoid using noncompetitively priced coal.

This situation will not last indefinitely, however: Low-sulfur coal markets may eventually tighten, and western rail competition may eventually lessen.

The Natural Gas Market

Many consider that the Amendments' principal winner was the natural gas industry. Yet most of the benefits for this side of the energy business will not materialize until the last part of this decade, as the Phase II SO_2 reductions loom and federal and state governments mandate low-emission vehicles for fleets beginning in 1998 (1996 in California).

Natural gas is expected to gain significant market share anyway—little of the projected demand is related to the Amendments. Many oil-fired plants already have switched to gas or are planning to switch soon. Regardless of environmental impact, utilities will build new gas combined-cycle plants, simply because gas prices are low enough and combined-cycle generating technologies have improved. Overall, U.S. gas consumption should increase from today's 18 trillion cubic feet (Tcf) to 23 Tcf by 2000, a jump of almost 22 percent. That's a turnaround from recent years: Due to sagging prices and lower volumes, gas utility sales sagged from $68 billion in 1984 to an estimated $46 billion in 1990, a drop of nearly 32 percent.

A LOOK AT REPOWERING

In the next 15 years, according to Bechtel Power Corporation, repowering with new combustion turbines or clean-coal technology will be the one of the major keys to containing electricity-generation costs, meeting the Clean Air Act Ammendments requirements, maintaining existing capacity, and even adding new capacity. There are four basic repowering options, which Bechtel reviewed in a recent paper:

- *Gas-fired steam boiler to gas-fired combustion turbine combined cycle system (CTCC):* Adding combustion turbines and heat-recovery steam generators to existing steam boilers could triple capacity. The heat rate typically would decline 35 percent.
- *Coal-fired steam boiler to gas-fired CTCC:* The benefits include the same capacity and efficiency increases as the first option, though the lower prices of coal offset some of the savings. True savings stem from emissions reductions and the fact that repowering may cost less than other forms of new or replacement power.
- *Coal-fired steam boiler to circulating fluidized bed combustion system (CFB):* Converting to CFB would not directly increase capacity but would increase efficiency, reduce emissions, and allow the use of lower-grade fuels. It could prove to be an economic replacement option as older plants deteriorate and suffer from low availability.
- *Coal-fired steam boiler to coal gasification combined cycle system:* Tripling the capacity of an older station is the main benefit, along with decreased heat rate and very clean emissions, even from low-grade fuel.

Bechtel emphasizes that the ability to repower is site-specific and that utilities should evaluate all these options on a system basis.

The depressed state of natural gas prices may offer good compliance options for electric utilities. Gas prices in 1991 appeared to have bottomed out at around $1.50 (annual average) per million cubic feet (Mcf), with some significant spot-market strengthening during late 1992 (though the price increases last September were probably temporary). Given favorable long-term contract terms offered by gas suppliers today, electric utilities should look carefully at potential ways to increase their use of gas as part of their compliance plan. There are several possibilities for them to consider:

- *Switching from oil to gas.* As mentioned earlier, electric utilities can, in some cases, switch from residual oil to natural gas at a net cost savings. In most locations, natural gas is competitive with or cheaper than low-sulfur residual fuel oil. Oil units that switch could be substitute units in 1995 and generate extra allowances and extra potential revenue. Also, recent pipeline expansions have directed gas to areas where supplies or transportation competition were limited.
- *Taking advantage of regulatory changes.* FERC's Order 636, when implemented, will make gas transportation capacity much more available to electric utilities.
- *Expanding capacity.* Electric utilities that need new capacity could repower oil/gas steam plants as combined-cycle gas units. (In such systems, the exhaust gases from a gas turbine go through a waste-heat recovery system, which in turn powers a steam turbine—the double-duty increases thermal efficiency.) To the extent that these units could switch from residual oil to gas, utilities can grasp the fuel-price and allowance advantages noted above. In addition, they acquire new capacity at a relatively low incremental capital cost, and plant efficiency significantly improves (generally by about 20–30 percent, though some claims are as high as 55 percent) with significant fuel savings. [See the sidebar, "A Look at Repowering."]

TABLE 3

MARKET SHARE FOR EMISSION-CONTROL EQUIPMENT
(By 1991 Revenues)

Air & Water Technologies	9.2%
Asea Brown Boveri	8.3%
General Electric Environmental	5.7%
Environmental Elements	5.5%
John Zink Company	4.7%
Wheelabrator	4.2%
Babcock & Wilcox	3.9%
Joy Technologies	3.9%
JWP	2.5%
Calgon Carbon	2.5%
SUBTOTAL	50.4%
Others	49.6%
TOTAL	100%

Source: Market Intelligence Research (Mountain View, CA) "The North American Air Pollution Control Technologies Market."

- *Switching from coal to gas.* Generally, because of coal's relatively low delivered fuel price, this conversion is not economically attractive, even when considering SO_2 emission reductions. Natural gas reburning or co-firing, however, provides NO_x reduction benefits and hence potential cost savings. Also, the ability to take advantage of lower summer prices for natural gas can be an attractive option for certain summer-peaking coal-fired units.

Technology Markets

Due to slowing demand in the 1980s, the emission-control equipment industry saw revenues and margins erode. Driven by the Amendments, however, the industry's average annual revenues for stationary sources should be higher (on average in 1990 dollars) by $2.3 billion to $3.4 billion from 1992 to 1995; and higher by $4.2 billion to $5.8 billion annually from 1996 to 2000. This growth adds substantially to the current $2.0 billion to $5.4 billion market.

Quite apart from revenue gains, the Amendments will change this industry in other ways. Notably, the potential customer base will widen. Titles I and III, for example, will extend air controls to some industries—electronics, fibers, and coatings manufacturers, for example—that have not traditionally needed such equipment.

A good number of equipment firms, large and small, will be competing for the new pool of revenues stemming from the Amendments. As indicated in Table 3, however, the industry's top ten players control half of the market—and they're positioned to maintain their current share.

Also, there should not be any concerns about meeting the increased demand for stationary-source control equipment, for three reasons:

- Both large and small firms are already geared up to meet the new and growing demand.
- The slow growth in the last half of the 1980s has left some excess capacity.
- In such markets as SO_2 control equipment, the near-term markets are much lower than anticipated, which has engendered competitive equipment pricing.

Clean-coal technologies also have spurred on new markets. Demonstration programs using retrofit SO_2 or NO_x control technologies—sorbent injection, for example—have shown considerable promise and potentially lower costs than many conventional designs. In addition, the Amendments permit changes in design philosophy, such as the use of a single absorber tower for wet scrubbing systems with no spares, which for conventional systems can reduce the costs per ton of pollutant removed.

The Amendments provide additional allowance incentives for such clean-coal repowering technologies as fluidized bed combustors and integrated gasification combined-cycle systems. Under the Phase II repowering extension provisions of Title IV, units contracting to install clean-coal repowering technologies receive an ef-

fective four-year delay (until 2004) in compliance. A unit planning to repower would receive additional SO_2 allowances, permitting it to operate at uncontrolled levels until the completion of the repowering project. Based on nonbinding submissions to the EPA, there is already some utility interest in this program. Several utilities, including American Electric Power and PSI Energy, plan to demonstrate these repowering technologies in the future. Approximately 10 gigawatts of older and smaller units, according to ICF Resources, will likely repower at the beginning of Phase II.

While there is less immediacy associated with advanced emission-control technologies, the electric utility industry should monitor developments closely—new choices could play an important role in Phase II compliance efforts.

Regulatory Treatment of DSM Investments

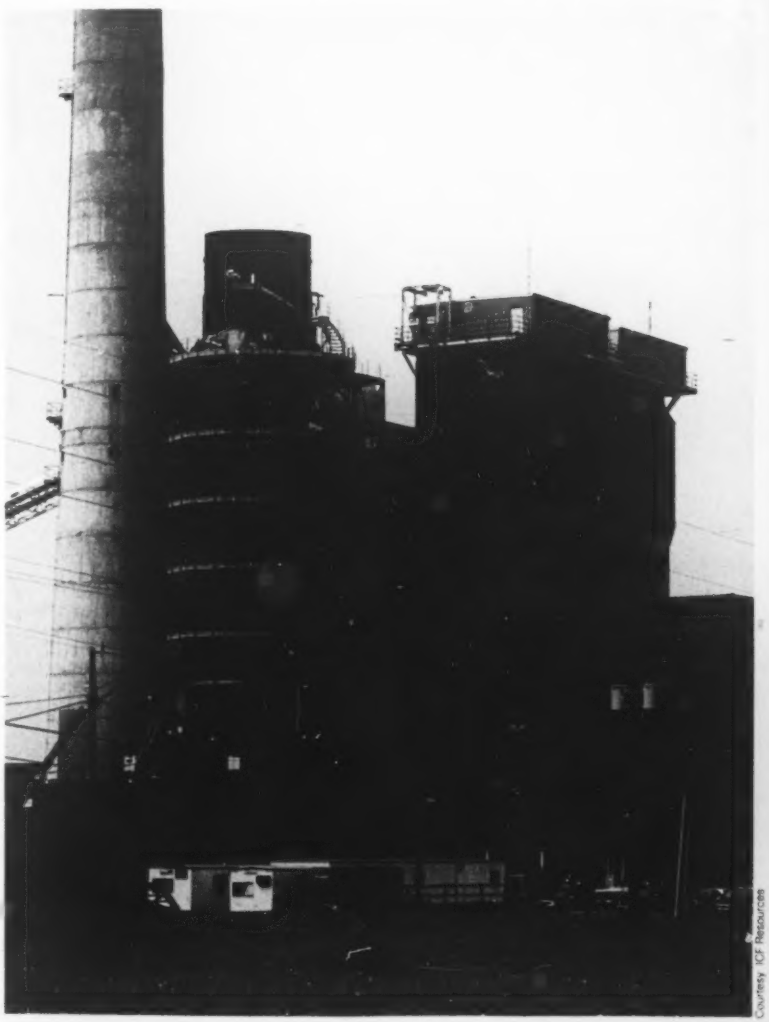
Over the past several years, utilities and regulators have made concerted efforts to reduce or eliminate regulatory disincentives for demand-side management programs (DSM). Nonetheless, many states still have only limited profit incentives associated with DSM—or none at all.

The Amendments provide for some incentives. The amount of SO_2 emissions are largely a function of fossil generation, so programs that reduce that generation (particularly the coal-fired sort) can increase the net supply of saleable allowances. In addition, the Amendments include a reserve of conservation allowances to be awarded to utilities with approved conservation programs based on a set formula and the number of kilowatthours saved. [See the sidebar, "Taking Advantage of Nega-Allowances."]

Neither incentive in itself is likely to provide significant cost savings to utilities pursuing conservation investments. There simply aren't that many incentive allowances, and cost savings associated with DSM still come from the avoidance of new generating capacity. But the Amendments do contain a requirement that all utilities applying for conservation allowances must have a rate structure that "guarantees net income neutrality." The intent of this provision was to "encourage the development of ratemaking frameworks that put conservation on an equal footing with electricity generation." In short, utilities in states without net income neutrality can use this provision as ammunition and work with their commissions over the next several months to develop a better regulatory framework.

Marketing New Technologies

In addition to the near-term revenue-enhancing and cost-reducing options in the allowance, fuel, and technology markets, utilities have longer-term diversification routes—marketing new emission-control technologies, ser-



Courtesy ICF Resources

Clean-coal technologies are creating new markets. Sorbent injection systems (like this one, with up to 80 percent SO_2 removal) may be an appropriate retrofit for a coal-fired plant.

TAKING ADVANTAGE OF NEGA-ALLOWANCES

The Environmental Protection Agency (EPA) wants utilities to know that they can earn "nega-allowances"—the value of allowances saved by reducing emissions by one ton of SO_2 through conservation and energy efficiency. The Clean Air Act Amendments of 1990 allow utilities to meet SO_2 reduction goals in conjunction with energy conservation programs.

It might seem like sleight-of-hand, but it could be helpful. EPA figures in the reductions in modified total resource cost (TRC) tests, which are often included in integrated resource plans. Once the value of the reduced emissions is quantified and factored in, the cost-effectiveness of a seemingly marginal conservation program can often be highlighted.

The Amendments provide for bonus allowances when a utility adopts a conservation plan; reduced utilization provisions (cutting down on the use of heavy-emission plants) give utilities allowances as well. But nega-allowances through conservation "accrue" automatically after compliance deadlines—the EPA does not require verification of reductions or energy savings derived from conservation programs.

Still, many utilities look on conservation and DSM as having extremely marginal roles in their compliance strategies. As part of its recently filed Title IV compliance plan, however, Centerior Energy Corporation includes a three-year, $35 million commitment to conservation programs for Cleveland Electric Illuminating and Toledo Edison.

Once it's finally passed by the Public Utilities Commission of Ohio, the plan will make Centerior the first midwest electric utility to use DSM as an explicit atmosphere cleanup tool.

At the same time, Centerior has agreed to consider purchasing emission allowances, as long as the prices of low-sulfur coal and allowances themselves are favorable. That breaks ground as well: For all the talk about the allowance market, most utilities have been leery of it. In fact, in a good number of Phase I compliance plans, the strategy of choice has been to build scrubbers, seemingly without much reliance on allowances.

At the October 1992 EEI Financial Conference, Eileen Claussen, director of the EPA office of atmospheric and indoor air programs, exhorted utilities to lengthen their list of compliance options. "Utilities can save hundreds of millions of dollars if they plan right," she said.

"Don't just look at scrubbers or low-sulfur coal," she urged. "Look at the allowance market, at gas cofiring, conservation and demand-side management, and other nontraditional options." Otherwise, a utility plan that simply scrubs or switches coal supplies is half-baked, she concluded.

EPA Administrator William Reilly echoed Claussen's sentiments at the October news conference to release the final SO_2 regulations. "We hope that in the way [utilities] respond to the law," he said, "they do not lose sight of the [market's] very substantial economic benefits."

vices, and expertise developed while complying with the Amendments.

The most promising growth area is the international emission-control market. In Europe, the European Commission has enacted numerous emission directives, which are certain to expand as eastern European countries accelerate the modernization of their economies. The World Bank estimates that it will take $200 billion to arrest eastern European air problems.

The newly industrialized nations of East Asia—South Korea, Hong Kong, Taiwan, and Singapore—also promise growth. Finally, the new North American trade agreement with emission-heavy Mexico may augur a strong U.S. export market.

The Amendments' technology-forcing aspects may represent the U.S. emission-control industry's strongest future competitive advantage. This might just reverse the trend of the 1980s, when firms in Japan and in Europe—responding to increasingly stringent emission-control requirements in their domestic markets—invested in and developed a new generation of emission-control technologies.

The electric utility industry can also participate in international markets through joint ventures, as many utilities are already doing in power projects overseas. In the same manner, they could market emission-control engineering, planning, and other services. New demand- and supply-side process improvements (even energy-efficient light bulbs) could travel abroad as well, especially if they represent lower capital-cost alternatives—particularly important for eastern Europe and Mexico, where capital is relatively scarce.

Choose or Lose

Obviously, electric utilities are aware of the risks in near-term compliance strategies. Capital investments hold more risks than noncapital expenditures—a scrubber investment, most pointedly, is in fact largely irreversible. Thus, if market or regulatory conditions change unexpectedly (if new global climate change legislation reduces the value of SO_2 allowances, for instance), the scrubber becomes more of an albatross than other compliance options, such as expenditures for fuel or allowances.

Banking allowances for eventual sale can be iffy as well—it is possible to buy too many. Banking them is different from (and riskier than) saving them to cover internal needs. Like a financial instrument, they carry market risks. Changes in environmental regulations or market conditions could reduce their value over time. As with other investments, utilities should diversify their portfolios and avoid overinvesting in allowances—they probably should constitute only a small portion of the utility's total financial assets.

But despite the costs, electric utilities must try to take advantage of strategies to reduce them and enhance competitiveness. They need to move aggressively, however, on current market conditions and specific regulatory alternatives, some of which could disappear in just a few years. ◆

in the furnace, circulating rapidly in vertical patterns. A quarter of the way up, secondary air is pumped in, producing even more upward turbulence. Heat transfer to the waterwall occurs as the orbiting particles come in contact with it.

As the particles become even smaller and reach the upper level of the furnace, they blow into the cyclone, or separator—a kind of upright cone or funnel. On the bottom of that funnel, the particles collect, to be injected through a seal pot (a one-way valve) back into the base of the furnace for recirculation.

When solids are too light or can be recycled no more, the flue gases and burned-out particulates flow with the extreme heat from the upper furnace and out the top of the cyclone, where they transfer their heat to the steam exhaust and create superheated steam. This also warms the intake water in the economizer. Cooled particulates are collected then, and the remaining exhaust gases and particulates flow to the bag house (a fabric filter or electrostatic percipitator). What remains of the exhaust after that is what is pumped to and out of the stack.

Variations on a Theme

There are a few major manufacturers involved in CFB boiler systems for electricity generation. Some of them are listed here, along with a brief description.

- *ABB Combustion Engineering Systems (Windsor, CT):* Uses a fluid bed heat exchanger (FBHE) to add further cooling when the waterwalls alone are not adequate. Some solids collected from the cyclone are diverted to the FBHE, where they cool by passing over several sections of heat-transfer surface in a dense-phase, low-velocity (unlike the circulating furnace) environment. The FBHE can be adjusted to create optimum combustion temperatures for different fuels.
- *Ahlstrom Pyropower (San Diego, CA):* For the Nova Scotia Power Corporation's 165 MW coal-fired plant, Ahlstrom Pyropower used its patented reheater to augment its CFB boiler (PYROFLOW) system. About three-quarters of the spent steam from the turbine, before it cools to water (which requires more energy to superheat again), is routed through a separate circuit back to the main heat exchange and superheated, a temperature jump requiring much less energy.
- *Babcock & Wilcox (Barberton, OH):* In B&W's system, solids hit an impact separator—rows of U-shaped beams hung vertically from the ceiling to form a labyrinth—at the top of the furnace. The first beams feed heavy solids directly back to the bed; smaller particles move further into the labyrinth and drop into a hopper, which forces them through an L-valve to the bed; particles reaching the labyrinth end flow past the superheater and into the "multiclone," toward disposal or more recirculation.
- *Combustion Power Company (Menlo Park, CA):* FI CIRC (fines circulating) fluid bed technology is the company's name for its hybrid system. It incorporates parts of CFB and "bubbling bed" technology (akin to CFB technology, but without forced fluidization). The structure height of 75 feet (as opposed to 120 feet for CFB boilers) and its rectangular construction may reduce construction time.
- *Foster Wheeler Energy Corporation (Clinton, NJ):* The company's cyclone is enclosed in Mono–Wall, a series of tubing that can attach to the furnace boiler circuitry. The structure, in effect, does double-duty—separating solids and transfering heat.
- *Riley Stoker Corporation (Worcester, MA):* The company's parent group, Deutsche Babcock, developed the Circofluid, which concentrates its efforts in the furnace by putting the superheater in the furnace's upper half, rather than beyond the cyclone. Primary air use is 70 percent, rather than 40 or 50 percent, and in the upper levels, the temperature reaches 970°C (1,760°F), about 8 percent higher than others.

Contributed by editorial staff

STATISTICAL REVIEW

1991 FUEL USE

In 1991, the total electric utility industry generated 1,896,957 million kilowatt-hours (kwh) from fossil fuels, up 632 million kwh from the 1990 total. Nuclear generation rose 7.2 percent to 612,309 million kwh.

The amount of electricity generated from oil declined 5.1 percent, giving oil 5.7 percent of the 1991 fossil-fuel-fired electricity total. Electricity generated from coal edged up 0.2 percent over the previous year, resulting in an 80.8 percent share. Gas-fired electricity rose 1.1 percent, for a 13.5 percent share.

As shown in Table 1, electric utilities consumed 756 million tons of coal in 1991, a 1.1 percent increase over 1990's 748 million total. Oil consumption fell 7.1 percent, while gas consumption rose 1.0 percent.

The fossil fuel data reported in Table 1 represent 98.6 percent of all utility generation from fossil fuels. The nuclear fuel data represent 99.9 percent coverage. The source for the table, which provides data for the nine census divisions of the country and Alaska and Hawaii, is the latest edition of *Statistics on Fuel Used to Generate Electricity by the Electric Utility Industry*, a report published annually by Edison Electric Institute's statistics department. (For statistics on 1991 fuel costs, also adapted from the report, see the "Financial Review" in this issue.)

Electricity generated by coal increased to 1,531,660 million kwh in 1991, up from 1,527,855 million in 1990. The East North Central census division (Wisconsin, Illinois, Indiana, Ohio, and Michigan) consumed the most coal to generate power, although less than it did in the previous year. The New England division

TABLE 1
TOTAL ELECTRIC UTILITY FUEL USE

	Coal—in Thousands of Short Tons			Oil—in Thousands of Barrels			Gas—in Millions of Cubic Feet			Nuclear—in Millions of Kilowatthours		
	1991	1990	%Chg.	1991	1990	%Chg.	1991	1990	% Chg.	1991	1990	%Chg.
New England	6,419	6,300r	1.9	41,061	44,566	(7.9)	46,131	65,408	(29.5)	33,997	33,512	1.4
Middle Atlantic	53,077	54,020	(1.7)	55,166	65,910	(16.3)	277,353	272,258	1.9	111,374	103,891	7.2
East North Central	167,847	169,901	(1.2)	4,836	3,640	32.8	41,873	33,564	24.8	123,917	115,028	7.7
West North Central	101,563	100,510	1.0	517	435	18.8	55,682	34,425	61.7	40,092	38,535	4.0
South Atlantic	124,639	128,283	(2.8)	63,414	52,928	19.8	229,966	208,083	10.5	153,070	140,429	9.0
East South Central	78,846	77,593	1.6	859	1,650	(47.9)	53,053	57,799	(8.2)	39,918	33,475	19.2
West South Central	122,863	115,243	6.6	631	1,132	(44.2)	1,408,487	1,419,119	(0.7)	46,356	41,308	12.2
Mountain	93,067	90,309	3.1	987	863	14.3	81,555	75,943	7.4	24,901	20,598	20.9
Pacific	7,181	5,470	31.3	1,101	10,497	(89.5)	462,144	461,318	0.2	38,683	44,509	(13.1)
Alaska & Hawaii	295	289	1.9	13,336	14,186	(6.0)	31,518	33,898	(7.0)	—	—	
Total U.S.	755,797	747,919r	1.1	181,908	195,807	(7.1)	2,687,762	2,661,815	1.0	612,309	571,283	7.2

Total may not equal sum of components due to independent rounding.
r = revised

(Maine, Vermont, New Hampshire, Massachusetts, Connecticut, and Rhode Island) used the least, although coal consumption there grew almost 2 percent. The Pacific division (Washington, Oregon, and California) saw the greatest percentage increase, 31.3 percent.

Consumption dropped in only three divisions, most sharply in the South Atlantic (Delaware, Maryland, West Virginia, Virginia, North Carolina, South Carolina, Georgia, and Florida). It grew at least 1.0 percent in Alaska and remaining census divisions, most sharply in the West South Central (Oklahoma, Arkansas, Louisiana, and Texas).

At the state level, Texas led the nation in coal use for power generation, consuming 85.5 million tons, 77 percent more than the second-place state, Ohio. In six states—California, Hawaii, Idaho, Maine, Rhode Island, and Vermont—and in the District of Columbia, electric utilities generated no electricity from coal.

Electricity generated by oil dropped from 114,617 million kwh in 1990 to 108,754 million in 1991. The Pacific division experienced the steepest decline, plunging 89.5 percent, or 9,396 thousand barrels. The Middle Atlantic (New York, New Jersey, and Pennsylvania) saw the largest drop, 10,744 thousand barrels.

Oil consumption for electricity generation rose in four of the nine divisions. It jumped 32.8 percent in the East North Central, the steepest increase nationwide. In absolute terms, the South Atlantic saw the greatest increase, using 10,486 thousand barrels more in 1991 than in 1990.

Florida used the most oil to generate electricity (48,588 thousand barrels), followed closely by New York (45,965 thousand barrels). Idaho and New Mexico used the least (1 thousand barrels each).

Electricity generated by gas rose to 256,543 million kwh in 1991, up from 253,852 million in 1990. The West North Central experienced the sharpest increase in gas use, 61.7 percent. The South Atlantic experienced the largest increase in absolute terms, jumping 21,883 million cubic feet, followed closely by the West North Central (North Dakota, South Dakota, Minnesota, Iowa, Nebraska, Kansas and Missouri), which increased its consumption by 21,257 million cubic feet.

In Alaska and three census divisions, gas consumption declined in 1991. The drop in New England, 19,277 million cubic feet, or 29.5 percent, was greater than the total drop in the other areas combined.

Among the states where gas was used to generate electricity in excess of that consumed by plant operations, Texas used the most (996,406 million cubic feet) and Kentucky used the least (63 million cubic feet).

Electricity generated by nuclear fuel jumped from 571,283 million kwh in 1990 to 612,309 million kwh in 1991. The Mountain (Montana, Idaho, Wyoming, Nevada, Utah, Colorado, Arizona, and New Mexico) division experienced the largest percentage increase, 20.9 percent, and the South Atlantic division experienced the largest absolute increase, 12,641 million kwh. Only one division, the Pacific, experienced a decline. There nuclear generation fell 5,826 million kwh in 1991, a drop of 13.1 percent from 1990's total.

Thirty-three states produced nuclear power in 1991.Output was greatest in Illinois (71,070 million kwh) and smallest in Oregon (1,464 million kwh).

Contributed by the Statistics Department of Edison Electric Institute.

FINANCIAL REVIEW

1991 FUEL COSTS

As shown in Table 1, the composite average cost per million British thermal unit (Btu) of fossil fuels consumed for electricity generation by the total electric utility industry in 1991 was 169.6 cents, a 2.6 percent decrease from the 174.1 cents averaged in 1990. On a cost-per-net-kilowatthour (kwh) basis, the composite average cost of fossil fuels dropped 2.8 percent, slipping from 1.80 to 1.75 cents.

The average cost of coal edged down 0.9 percent per ton in 1991. On a cost-per-million-Btu-consumed basis, the average cost rose slightly to 151.5 cents, an increase of 0.2 percent from 1990.

Over the same period, oil costs dropped significantly. The average cost per barrel for 1991 was $18.50, 11.3 percent lower than 1990's $20.85 average. The average cost per million Btu consumed was down 11.5 percent.

The average cost of gas per thousand cubic feet fell 6.1 percent to 225.85 cents from the previous year's 240.53 cents. On a per-million-Btu-consumed basis, the average dropped 5.6 percent.

The average cost of nuclear fuel per net kwh was .668 cents in 1991, 6.7 percent lower than the .716 cents averaged in 1990. The average cost per million Btu consumed was 62.41 cents, down 4.0 percent from 65.01 cents.

The data given in Table 1 are from the latest edition of *Statistics on Fuel Used to Generate Electricity by the Electric Utility Industry*, a report published annually by Edison Electric Institute's statistics department. (For data on 1991 fuel use, see the Statistical Review in this issue.)

Contributed by the Statistics Department of Edison Electric Institute.

TABLE 1
AVERAGE FUELS COSTS–TOTAL ELECTRIC UTILITY INDUSTRY

		Fossil Composite Averages		Coal		Oil		Gas		Nuclear	
	Year	Cost per Million Btu Consumed	Cost of Fuel per Net kwh	Cost per Million Btu Consumed	Cost per Short Ton	Cost per Million Btu Consumed	Cost per Bbl	Cost per Million Btu Consumed	Cost per MCF	Cost per Million Btu Consumed	Cost per Net kwh
New England	1991	229.2¢	2.27¢	182.9¢	$48.07	261.7¢	$16.56	215.6¢	220.78¢	65.17¢	.691¢
	1990	250.6r	2.54	184.3r	48.17r	290.2	18.36	247.0	253.35	74.60	.788
Middle Atlantic	1991	207.7	2.14	167.1	41.85	319.0	20.14	261.1	267.23	65.52	.708
	1990	216.2	2.22	161.4	40.22	359.8	22.32	269.5	277.89	60.45	.663
East North Central	1991	160.7	1.65	158.7	34.68	341.9	21.20	229.9	161.41	60.40	.651
	1990	160.3	1.65	158.7	34.61	377.3	23.15	225.0	120.28	65.42	.702
West North Central	1991	118.4	1.29	116.0	20.02	427.2	25.14	180.3	178.51	53.68	.572
	1990	119.2	1.31	117.2	20.57	427.3	25.11	196.8	195.72	52.23	.554
South Atlantic	1991	188.5	1.88	176.7	43.67	264.3	16.68	214.7	218.60	56.18	.600
	1990	193.3	1.92	177.2	43.68	308.5	19.43	253.5	257.60	59.28	.638
East South Central	1991	148.2	1.52	147.3	35.29	338.8	21.10	160.7	164.35	81.10	.904
	1990	152.5	1.54	150.6	35.96	322.4	20.02	181.4	186.99	84.86	.918
West South Central	1991	174.8	1.83	153.1	23.35	511.7	30.56	201.9	208.49	65.44	.701
	1990	179.2	1.91	150.3	24.01	481.1	28.96	213.9	221.91	72.56	.779
Mountain	1991	122.0	1.29	117.6	22.84	478.5	28.47	191.8	193.76	70.69	.742
	1990	118.6	1.27	113.6	22.22	417.6	25.00	210.6	216.89	77.94	.810
Pacific	1991	255.0	2.67	134.2	21.31	365.3	22.31	282.5	289.64	62.86	.669
	1990	274.4	2.89	148.1	24.00	348.6	21.44	287.7	298.31	69.03	.727
Alaska	1991	158.1	1.86	193.7	30.30	445.2	25.53	118.0	118.34	—	—
	1990	148.1	1.84	184.4	29.06	639.0	37.06	112.7	113.04	—	—
Hawaii	1991	374.4	4.04	—	—	374.4	23.16	—	—	—	—
	1990	376.7	4.30	—	—	376.7	24.83	—	—	—	—
Total U.S.	1991	169.6	1.75	151.5	31.45	293.8	18.50	221.1	225.85	62.41	.668
	1990	174.1	1.80	151.2	31.73	332.1	20.85	234.2	240.53	65.01	.716

r= revised

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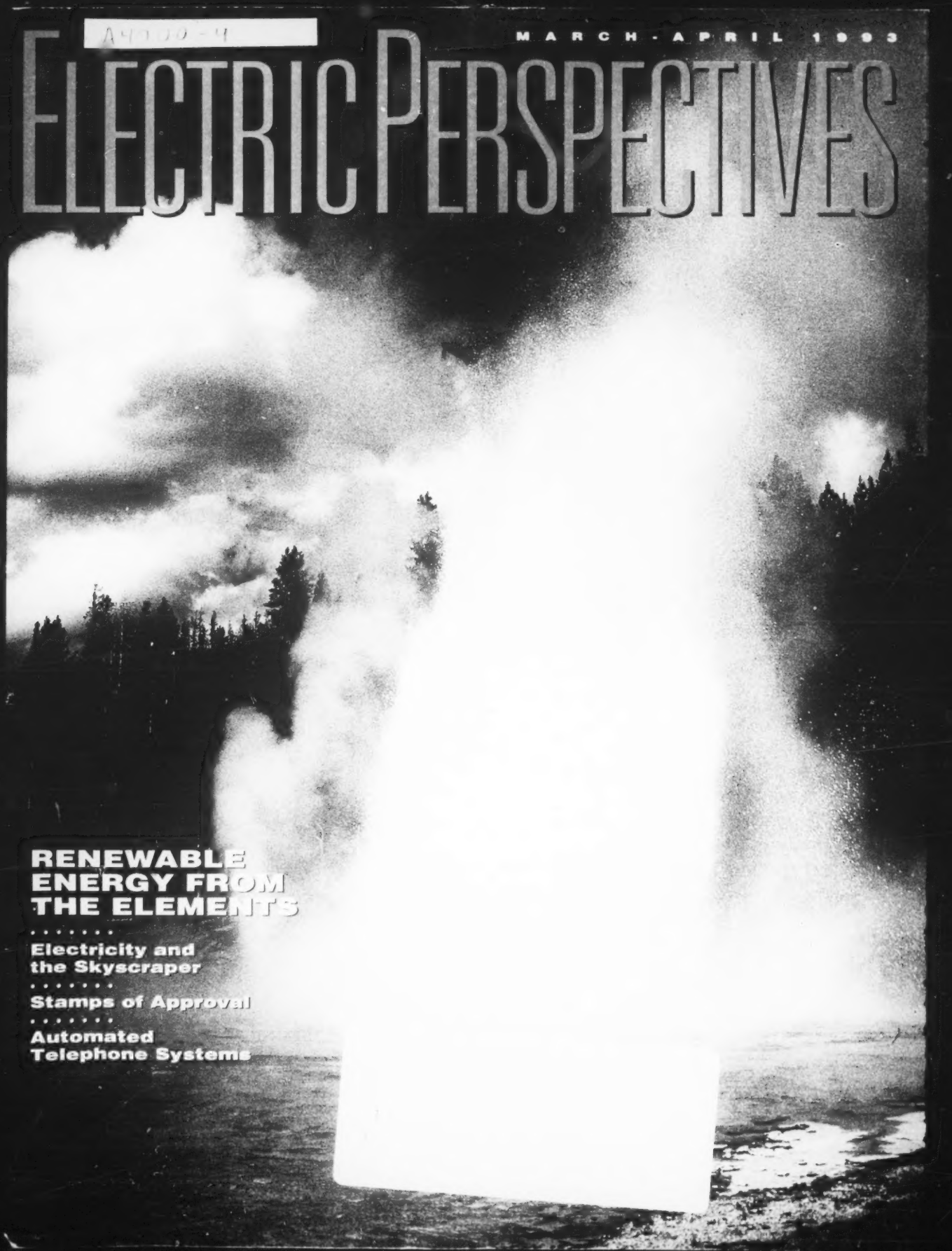
ELECTRIC PERSPECTIVES



RENEWABLE ENERGY FROM THE ELEMENTS

Electricity and the Skyscraper

Stamps of Approval

Automated Telephone Systems

THE MAGAZINE FOR MANAGEMENT IN AMERICA'S INVESTOR-OWNED ELECTRIC UTILITIES

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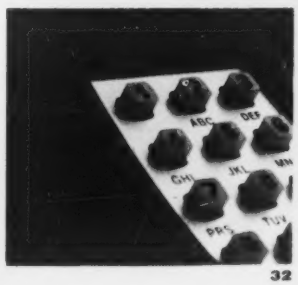

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NEWS & TRENDS

TOMORROW'S GREEN HOUSE

The emergence of green consumers, customers who alter their shopping habits to select recycled, recyclable, biodegradable, or energy-efficient products, is an ongoing trend. Yet for the largest purchase consumers are likely to make—their homes—green customers often lack comprehensive guidance.

The electric utility industry is trying to change that.

The goal of the Three E Program now under development is to help customers identify homes that are environmentally sound and energy-efficient through their use of electricity—hence the "Three-E" label. Building on utilities' long experience in certifying energy-efficient homes, the program will stretch energy-efficiency performance beyond current practice, indirectly resulting in a host of environmental benefits. In addition to efficient energy use per se, water conservation, indoor air-quality improvement, and construction-waste reduction are among several possible factors to be considered by the program.

Electric utilities hope to work with homebuilders, equipment manufacturers, and environmental groups to develop Three E guidelines.

EV CONSORTIUM AS ECONOMIC BOOSTER

Calstart is the private/public California consortium that's coming up with an electric vehicle to meet the state's looming clean-air requirements. So far, it's received $6 million in state and federal help and $14 million from its 40 members, which include Southern California Edison and Pacific Gas & Electric. With its other two projects—promoting electric buses and EV infrastructure development—the consortium could create more than 55,000 California jobs.

Indeed, Calstart is trying to grow the state's EV industry and recharge the troubled defense industry by making its EV a showcase of California technologies. International Automobile Design (Huntington Beach) will assemble the car with components from several companies:

- Kaiser Aluminum & Chemical (aluminum frame)
- Fairchild Manufacturing (plastic underbody)
- Avery Dennison (dry body paint)
- Pirelli Armstrong Tire (low-resistance tires)
- IWON Motronics (electric-drive motor)
- Delta Tau Data Systems (motor efficiency controller)
- International Rectifier (semiconductors)
- ITT Cannon (wires & connectors)
- Trojan Battery (lead-acid battery)
- Group IX Systems (battery monitors)
- HUB Engineering (battery housing)
- Hughes Power Control Systems (battery-charging)
- Dowty Aerospace (regenerative-energy braking system)
- Feher Design (variable temperature seat)
- Aerojet (collision warning system)
- Amerigon (energy management & safety systems)
- Audio Navigation Systems (voice-recognition navigation system).

HELPING THOSE IN NEED

In 1987, about 193,000 people received assistance through fuel funds. These charitable contributions help low-income customers, usually on an emergency basis, pay their energy bills. In 1991, that number had grown to 317,500, according to a survey conducted by the National Fuel Funds Network (NFFN).

The "National Survey of Energy Assistance Efforts" was released on National Fuel Funds Day (December 8) at what NFFN billed as the nation's largest housewarming.

The survey also showed vigorous public interest in the nation's 130 fuel funds and found that in the past 12 years, the private sector had distributed more than $320 million (70 percent of which came from electric and gas utility customer programs) to households, some of which didn't qualify for the federal Low-Income Home Energy Assistance Program (LIHEAP). Such bill-payment assistance is critical: On average, low-income families pay more than 13 percent of their incomes for energy—four times what middle-income Americans pay. For many families during the winter, according to NFFN, the choice often comes down to heating or eating, an unhealthy dilemma.

But fuel funds can take on only a small part of the need. Last year, LIHEAP was able to provide an average of just $189 to 6.2 million households. In another study, Citizen's Energy Corporation offered data showing that half of non-LIHEAP recipients of fuel funds are families with children and a third have lived with unemployment for some time. Moreover, all of these households have average incomes at or below the poverty line. In fact, Citizen's Energy said, LIHEAP helps only about a third of those qualifying for its assistance—altogether, more than 15 million households. For fiscal 1993, however, LIHEAP funding was cut to $1.35 billion from $1.5 billion—and that means less help for fewer households, however vigorous public support is.

For more information on NFFN, contact Cynthia Liston at EEI, 202/508-5661.

CHOOSING THE ROUTE FOR ADVANCED PLANT DESIGNS

The Advanced Reactor Corporation—a group formed by 16 electric utilities to support the development of new nuclear plant designs—has announced plans to negotiate contracts with the Department of Energy (DOE), General Electric, and Westinghouse Electric to perform "first-of-a-kind" (FOAK) engineering required for a standardized plant design proposed by each company.

The group selected GE's Advanced Boiling Water Reactor (a 1,300-megawatt (MW) plant) and Westinghouse's AP600 (a 600-MW pressurized-water plant).

For the nuclear industry, this is an important first step for fostering new construction. FOAK engineering goes beyond safety certification by the Nuclear Regulatory Commission and documents standardized designs that will allow utilities to project construction costs and schedules before ordering a new plant.

For the two designs, Advanced Reactor Corporation has committed more than $50 million; the manufacturers' contribution will be more than $50 million as well; and DOE will invest $100 million over five years. The government will recoup some of its money from sales of the two designs.

Contracts with General Electric and Westinghouse are scheduled to be finalized this spring, and the two designs should be complete sometime in 1996.

OUTSOURCING INFORMATION TECHNOLOGY

Washington Water Power Company, a Spokane-based utility serving parts of Washington, Oregon, Idaho, and California, recently farmed out a lot of its work.

The utility outsourced its information technology (IT) services to EDS. Under the 10-year agreement, EDS will take care of WWP's data processing, application development, information-center support, and system maintenance.

WWP believes it is the first U.S. investor-owned electric utility to make such a move. It hopes that EDS will integrate its business processes and therefore enhance its core business and customer service. Outsourcing the IT services provides them with such benefits as technology refreshment, economies of scale, and flexibility of resources.

All of WWP's IT professionals have now become employees of EDS, which will provide an on-site account manager as well as administrative and technical support staff. During the 10-to-12-month transition period, additional technical support staff will be on hand.

Here are the planned expenditures (in $millions) on software and related services in U.S. electric, natural gas, and combination utilities:

Area	1990	1995	average annual increase
Transaction processing services	201	333	11%
Turnkey systems	85	145	11%
Applications software	185	334	13%
Systems operations	45	90	15%
Systems integration	469	924	15%
Professional services	234	385	10%
Network services	26	38	8%
Total	1245	2249	13%

Source: Electrical World, from Input

- *GE Meter & Control (Somersworth, NH; 603/692-2100):* Meters for residential and commercial/industrial sites that are remotely readable using powerline carrier technology. Partnership with Ericsson adds radio communications and links from utility headquarters to local powerline carrier networks.
- *Iris Systems (Apple Valley, MN; 612/322-4224):* Multi-link, two-way radio communication networks for AMR, distribution automation, and DSM for electric, gas, and water utilities.
- *Itron, Inc. (Spokane, WA; 509/924-9900):* Radio-based meter-reading products (including hand-held terminals for walk-by AMR and drive-by systems from their EnScan subsidiary).
- *Landis & Gyr (Lafayette, IN; 317/742-1001):* Solid-state and electromechanical meters with optional add-in electronics for AMR. Connections with Itron, Metricom, and other companies provide long-range communications.
- *Metricom, Inc. (Los Gatos, CA; 408/399-8200):* System-wide communication networks using radio and powerline carrier for AMR, distribution automation, and DSM.
- *Motorola, Inc. (Schaumburg, IL; 708/576-1000):* Radio systems for local and wide-area communications and control. AMR relationships established with ABB and other meter suppliers.
- *Nertec Design, Inc. (Granby, Quebec, Canada; 514/375-0555):* Dial-inbound AMR products; meter interface units and application software.
- *Schlumberger Industries, Inc. (Norcross, GA; 404/368-3500):* Meters and associated meter-reading products. AMR technologies include walk-by radio, cellular telephone, and dial-inbound systems with meter interface units and head-end software.
- *Utility Translation Systems (Raleigh, NC; 919/876-2600):* Software for utilities for AMR and other applications, all with universal interfaces to software products from other suppliers.

Richard Alexander is president of Alexander & Associates, which recently published *Automating Electric Utility Meter Reading*. For more information, call 714/642-0101.

FINANCIAL REVIEW

THIRD QUARTER EARNINGS JUMP 17.9 PERCENT

A $1.4 billion drop in non-recurring income-reducing items boosted investor-owned electric utility earnings per share before extraordinary items from $0.67 for the third quarter of 1991 to $0.79 for the third quarter of 1992. Last year, non-recurring items totaled only $0.1 billion for the quarter; the previous year, due to write-offs of disallowed construction costs, they totaled $1.5 billion. On a 12-month basis, earnings per share before extraordinary items increased 6.7 percent, up from $1.79 to $1.91. (See Table 1.)

Despite a 1.1 percent decrease in sales caused by the cooler than unusual weather, total electric operating revenues increased 0.9 percent, from $44.7 billion in the third quarter of 1991 to $45.1 billion in the third quarter of 1992. The slight gain reflects the impact of base rate increases and electric rate adjustment mechanisms effective during the last third quarter but not in the previous one.

Total electric operating expenses for the quarter grew 2.4 percent, from $34.3 billion to $35.1 billion, pushing the operating ratio up from 76.8 to 77.9. Increases in purchased power and net interchange expenses led the way. The 12.3 percent jump was caused by increases in both the volume and the price of such purchases, especially from nonutility generators, who saw natural gas prices rise over the period. Over the same period, investor-owned electric utilities experienced a 2.7 percent drop in fuel expenses, reflecting the 2.3 percent decline in their net generation. For the quarter, purchased power represented 11.5 percent of the utilities' total operating revenues, the highest level reached since Edison Electric began tracking it in the fourth quarter of 1988.

Operation and maintenance expenses also rose, adding $434 million more to total third quarter expenses in 1992 than in 1991. Growth in conservation programs, scheduled plant outages, and costs associated with early retirement programs caused the increase.

At the same time, increased refinancing of long-term debt at lower yields and shorter maturities pushed net interest expenses and charges down 3.5 percent to $3.9 billion. The drop helped improve the industry's pre-tax interest coverage ratio without allowance for funds used during construction (AFUDC) to 3.50 times for the third quarter of 1992 versus 3.21 times for the third quarter of 1991.

AFUDC decreased 6.6 percent from $314 million to $294 million. The ratio of AFUDC as a percentage of net income available for common was 4.7 percent, down from 6.0 percent. Total phase-in plan accruals were also down, contributing $107 million less to income in the third quarter of 1992 than in 1991.

The return on average common equity (at the common stock level) excluding net nonrecurring items was 11.2 percent for the year ending September 30, a slight decrease from the 11.3 percent recorded for

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TABLE 1

INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY STATEMENT OF INCOME

(Millions of Dollars)

	Three Months Ending September 30,			Twelve Months Ending September 30,		
	1992	1991r	%Change[2]	1992	1991r	% Change[2]
Total Electric Operating Revenues[1]	$45,096	$44,709	0.9	$158,472	$155,379	2.0
Electric Operating Expenses						
Fuel	$7,698	$7,914	(2.7)	$28,987	$30,432	(4.7)
Purchased Power & Net Interchange	5,165	4,598	(12.3	16,509	15,028	9.9
Other Operation & Maintenance	10,751	10,317	4.2	43,180	421,553	3.9
Depreciation & Amortization	4,359	4,211	3.5	17,030	16,217	5.0
Costs Deferred Under Rate Phase-In Plans	27	(36)	N.M.	(13)	(284)	(95.5)
Taxes Other Than Income Taxes	3,357	3,328	0.9	12,808	12,173	5.2
Income Taxes: Federal & Other	3,059	3,630	(15.7)	7,416	8,021	(7.5)
Deferred Income Taxes	794	386	105.6	2,375	1,627	46.0
Investment Tax Credits, Net	(73)	(21)	252.9	(374)	(218)	71.2
Total Electric Operating Expenses	$35,138	$34,329	2.4	$127,919	$124,548	2.7
Electric Operating Income	$9,959	$10,381	(4.1)	$30,553	$30,831	(0.9)
Other Utility Operating Income	34	25	36.4	1,259	1,231	2.2
Total Utility Operating Income	$9,993	$10,406	(4.)	$31,812	$32,063	(0.8)
Other Income & Deductions,Net	$478	($892)	N.M.	396	($1,198)	N.M.
Phase-in Deferrals	39	83	(53.2)	231	484	(52.2)
Allowance for Other Funds Used During Construction	159	176	(9.8)	586	771	(24.0)
Total Income Before Interest Charges	$10,668	$9,773	9.2	$33,025	$32,120	2.8
Interest Charges						
Interest on Long-Term Debt	$3,583	$3,651	(1.9)	$14,902	$15,160	(1.7)
Other Interest Expenses & Charges	498	578	(13.8)	1,613	1,891	(14.7)
Allowance for Borrowed Funds Used During Construction	(135)	(138)	(2.5)	(534)	(634)	(15.8)
Net Interest Expenses & Charges	$3,947	$4,091	(3.5)	$15,981	$16,417	(2.7)
Net Income Before Extraordinary Items	$6,722	$5,682	18.3	$17,045	$15,702	8.5
Extraordinary Items	(1)	0	N.M.	(348)	7	N.M.
Cumulative Effect of a Change in Accounting Principle	0	0	N.M.	110	125	(12.6)
Net Income	$6,721	$5,682	18.3	$16,806	$15,835	6.1
Preferred Dividends Declared	473	491	(3.7)	49	1,945	5.3
Net Income Available for Common	$6,248	$5,190	20.4	$14,757	$13,890	6.2
Common Dividends Declared	3,586	3,466	3.5	14,458	13,669	5.8
Additions to Retained Earnings	$2,662	$1,724	54.4	$299	$221	35.0
Average Shares Outstanding (Millions)	7,887	7,715	2.2	7,838	7,690	1.9
Earnings Per Share Before Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle	$0.79	$0.67	17.9	$1.91	$1.79	6.7
Earnings Per Share After Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle	$0.79	$0.67	17.9	$1.88	$1.81	3.9
Common Dividends Per Share	$0.45	$0.45	0.0	$1.84	$1.78	3.4

SOURCE: EEI Survey Data and Standard and Poor's Compustat Services, Inc.

[1]Revenues are adjusted for intra-industry electricity sales for resale.

[2]Percent changes may reflect independent roundings.

r-Revised to reflect company restatements.

N.M.-Not Meaningful.

the previous year. The dividend payout ratio excluding net non-recurring items was 85.4 percent for the year, up from 78.1 percent.

Balance Sheet

Construction work in progress (CWIP) increased 15.8 percent from $21.1 billion at September 30, 1991, to $24.5 billion a year later. (See Table 2.) The increase was due in part to expenditures associated with the construction of gas-fired combined cycle units by one company, a nuclear plant by a second company, and a natural gas pipeline expansion project by a third company.

The common equity capitalization ratio rose from 43.3 percent as of September 30, 1991, to 43.8 percent a year later. An estimated $1.5 billion in new common stock issuance over the 12-month period accounted for the increase (Ebasco Business Consulting Services, Inc.). The proportion of preferred stock decreased from 7.2 to 7.1 percent; long-term debt decreased from 49.5 to 49.0 percent.

Tables 1 and 2 are based on unaudited reports submitted by a sample representing all investor-owned electric utility companies. In a few cases data are adjusted to reflect the consolidated entity and are supplemented with Standard & Poor's Compustat Services, Inc. Prior year data are revised to reflect all company restatements.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

TABLE 2
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY BALANCE SHEET
(Millions of Dollars)

Assets	September 30, 1992	September 30, 1991r	% Change[2]
Utility Plant[1]			
Utility Plant (Including Nuclear Fuel)	$547,394	$526,841	3.9
Less Accumulated Depreciation	180,793	166,059	8.9
Total	$366,600	$360,781	1.6
Construction Work in Progress	24,487	21,152	15.8
Net Utility Plant	$391,087	$381,933	2.4
Investments	30,461	29,043	4.9
Current Assets	48,562	47,415	2.4
Deferred Debits	39,873	35,325	12.9
Total Assets	$509,983	$493,717	3.3
Capitalization & Liabilities			
Capitalization			
Common Stock	$100,078	$95,306	5.0
Retained Earnings	56,044	55,742	0.5
Preferred Stock	25,473	25,021	1.8
Long-Term Debt	174,801	172,891	1.1
Total Capitalization	$356,396	$348,960	2.1
Current Liabilities			
Short-Term Debt	$8,594	$9,762	(12.0)
Long-Term Debt Due Currently	12,669	9,203	37.7
Other Current Liabilities	37,468	35,673	5.0
Total Current Liabilities	$58,731	$54,639	7.5
Deferred Credits			
Capital Lease Obligations, Non-Current Portion	$3,337	$3,647	(8.5)
Accumulated Deferred Income Taxes	56,195	53,183	5.7
Accumulated Deferred Investment Tax Credits	14,423	15,057	(4.2)
Other Deferred Credits	20,900	18,230	14.6
Total Deferred Credits	$94,856	$90,118	5.3
Total Capitalization & Liabilities	$509,983	$493,717	3.3

Source: Edison Electric Institute Survey Data and Standard and Poor's Compustat Services, Inc.
[1]Includes non-electric plant.
[2]Percent changes may reflect independent roundings.
r-Revised to reflect company restatements.

STATISTICAL REVIEW

THIRD QUARTER SALES DOWN 1.1 PERCENT

Electricity sales to ultimate customers by investor-owned electric utilities fell 1.1 percent from 577.8 million megawatthours (MWh) in the third quarter of 1991 to 571.4 million MWh in the third quarter of 1992. The drop reflects the cooler-than-normal weather most of the country experienced last summer. Compared to the third quarter of 1991, cooling degree days dropped 18.0 percent. Cooling degree days for the quarter were 11.8 percent below the seasonal average.

Sales to residential customers, the most weather-sensitive customer class, fell 4.3 percent from 198.0 million MWh for the third quarter of 1991 to 189.4 million MWh for the third quarter of 1992. Revenues from this customer class dropped 2.7 percent.

At the same time, the impact of the weather was moderated somewhat by healthy economic growth, which boosted industrial sales from 187.3 to 189.4 million MWh, a gain of 0.9 percent over the third quarter of the previous year. Similarly, revenues from industrial customers increased 1.4 percent.

Sales to commercial customers decreased 0.5 percent, from 174.4 million MWh to 173.6 million MWh. Nonetheless, revenues from this class grew 1.7 percent as a result of a 2.3 percent increase in the average revenue per kilowatthour sold.

The 1.1 percent drop in total sales reflects the 2.3 percent decline in net generation for the third quarter of 1992. Still, preliminary statistics indicate that generation for the year grew 0.4 percent compared to 1991.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

TABLE 1
SECOND QUARTER CUSTOMER, SALES, AND REVENUE DATA FOR INVESTOR-OWNED ELECTRIC UTILITIES

	Three Months Ending September 30,			Twelve Months Ending September 30,		
	1992	1991	% Change	1992	1991	% Change
Number of Customers						
Residential	75,362,098	74,633,441	1.0	75,167,569	74,412,857	1.0
Commercial	9,466,447	9,374,894	1.0	9,425,488	9,343,645	0.9
Industrial	410,966	409,508	0.4	398,335	394,662	0.9
Street & Highway	148,388	145,230	2.2	148,042	143,879	2.9
Other Public Authorities	171,773	170,087	1.0	171,376	166,389	3.0
Railroads	23	23	0.0	23	23	0.0
Interdepartmental	482	467	3.2	523	465	12.5
Total Customers	85,560,177	84,733,650	1.0	85,311,356	84,461,920	1.0
Electricity Sales (MWh)						
Residential	189,410,883	198,024,912	(4.3)	676,263,754	686,910,610	(1.5)
Commercial	173,550,543	174,417,709	(0.5)	622,898,970	620,691,163	0.4
Industrial	189,290,367	187,515,096	0.9	723,787,949	715,679,352	1.1
Street & Highway	2,530,018	2,481,759	1.9	10,604,848	10,489,176	1.1
Other Public Authorities	15,713,615	14,468,991	8.6	57,327,507	53,726,829	6.7
Railroads	622,461	628,497	(1.0)	2,501,618	2,548,564	(1.8)
Interdepartmental	301,877	303,628	(0.6)	1,251,965	1,100,917	13.7
Total Sales	571,419,764	577,840,592	(1.1)	2,094,636,611	2,091,146,611	0.2
Revenues ($000)						
Residential	17,029,432	17,509,577	(2.7)	58,057,942	57,764,914	0.5
Commercial	14,145,435	13,905,425	1.7	48,643,809	47,702,056	2.0
Industrial	10,204,855	10,064,837	1.4	36,700,350	36,057,959	1.8
Street & Highway	327,749	318,943	2.8	1,308,473	1,276,841	2.5
Other Public Authorities	812,710	781,276	4.0	2,909,260	2,796,692	4.0
Railroads	47,042	47,115	(0.2)	176,146	175,995	0.1
Interdepartmental	26,098	25,437	2.6	71,695	92,071	(22.1)
Total Revenues	42,593,322	42,652,610	(0.1)	147,867,677	145,866,529	1.4

Source: Edison Electric Institute, Statistics Department

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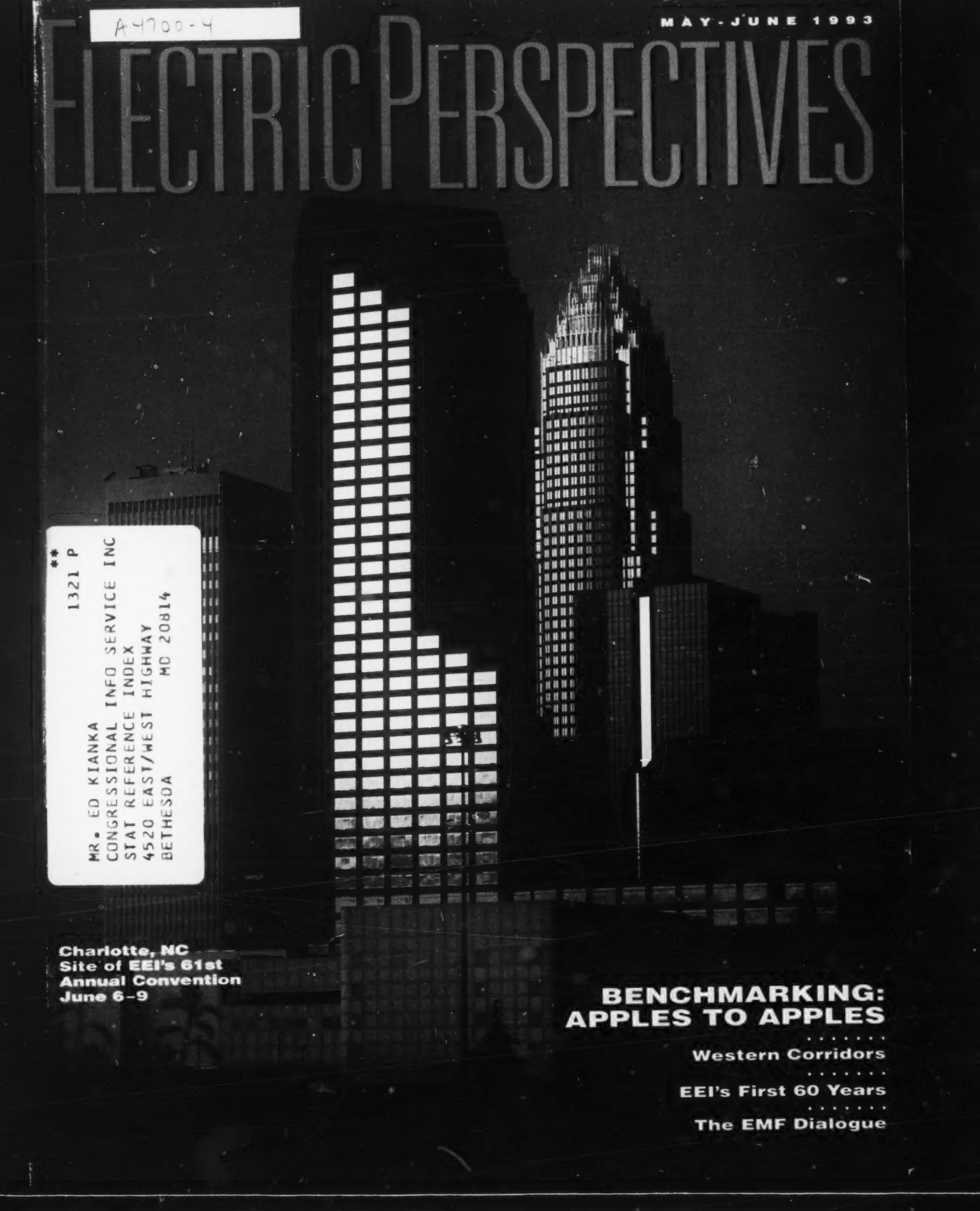
MAY-JUNE 1993

ELECTRIC PERSPECTIVES



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BENCHMARKING: APPLES TO APPLES

Western Corridors

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The EMF Dialogue

THE MAGAZINE FOR MANAGEMENT IN AMERICA'S INVESTOR-OWNED ELECTRIC UTILITIES MAY-JUNE 1993 VOLUME 17, NUMBER 3

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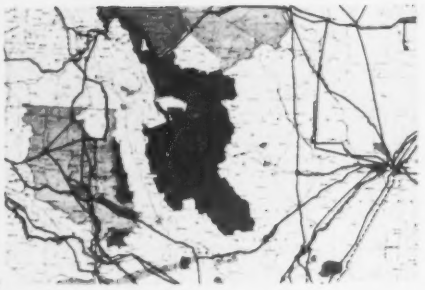

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FEATURES

THE MEASURE OF A UTILITY

Competitiveness and quality improvement don't exist in a vacuum. Benchmarking can be a critical component—it gets a company to collect process-related data and measure itself against others in the industry. The trick is to compare apples to apples.

BY LYNDA GMOHUNDRO AND JOSEPH ALBINO

THE FUTURE OF WESTERN CORRIDORS

The 1992 *Western Regional Corridor Study* demonstrates a cooperative effort between federal land agencies and utilities from 11 western states to plot a course for growth in a changing country.

BY CARL BARNETT

EDISON ELECTRIC INSTITUTE: THE FIRST 60 YEARS

From the depths of the depression years through World War II and up to the energy tax debate of today, EEI has helped the electric utility industry successfully meet the challenges of providing reliable, economical electricity to customers across the nation.

BY BARRY GRICKMEIR

EMF: THE PROCESS OF DIALOGUE

With great speed, EMF has moved from background to foreground in the public debate. What do customers think? How should utilities respond?

BY GENE POKORNY

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PRESIDENT'S MESSAGE

They say that you don't know where you're going until you know where you've been. That's certainly true for our industry—and from where we stand today, it's easy to have at once a proud sense of history and an exciting outlook on the future.

Sixty years ago, when the industry created Edison Electric Institute, electric utilities had begun to feel the binds of regulation—a new situation for them then. Today, regulation has altered its aspect, and that change has presented us with a whole new universe of opportunities.

Sixty years ago, we helped build machines and systems that built economic might. Today, we are the critical link to the electronic information superhighway, the electric transportation infrastructure, and the environmentally safe electrotechnologies that will drive our economy into the coming century.

Sixty years ago, we were busy expanding a network to bring power to all Americans at home and at work. Today, we're bringing power and experience to countries around the globe who are eager to duplicate our efficiencies and economic growth.

And sixty years ago, we provided customers with efficient, economical electric power. Today, that is still our essential task.

Looking Behind, Thinking Ahead

But we can't spend very long musing on where we've been or even where we are. We have to keep moving forward. There are large questions behind so many of today's issues—questions that have enormous bearing on the way we do business and provide service. They need our attention and resolve.

Consider the subjects in this issue. You may read Lynda Omohundro's and Joseph Albino's article on benchmarking and applaud the desire for quality and customer satisfaction. Behind that article are the larger questions of increased competition, company positioning, and market share.

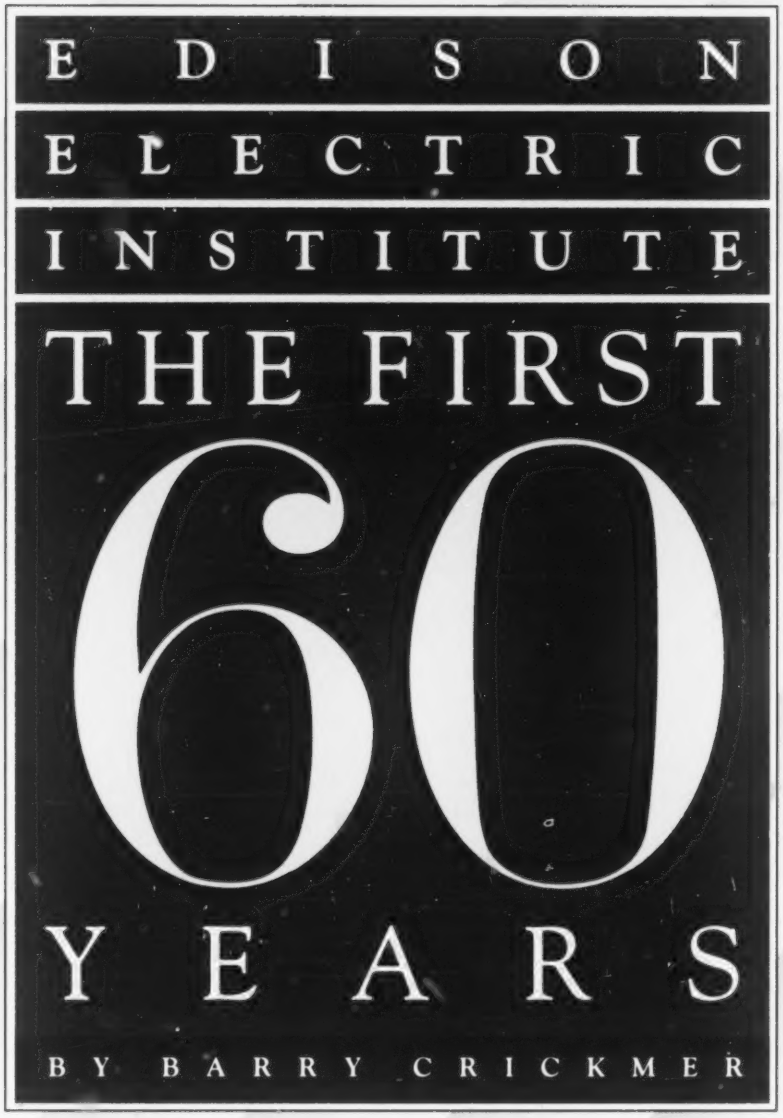
In Carl Barnett's article on the Western Regional Corridor Study, you may applaud the work of the Western Utility Group and its efforts to work cooperatively with federal land agencies. But there is a larger question, too: How does our industry plan necessary transmission expansion—and provide economic growth—as its options become more and more physically limited?

As you examine the public's view of EMF in Gene Pokorny's piece, you may be surprised or puzzled at some of the reactions. Behind them are legitimate questions about the possible effects of EMF—and behind those questions are the needs for further research and for continuing, constructive communication with our customers.

And you may read Barry Crickmer's review of EEI's last 60 years and reflect on the milestones and progress that have marked our industry since its birth in the late 1800s. Whether you're reading it at EEI's 61st annual convention in Charlotte, at home, or at work, you'll undoubtedly feel proud to be part of an industry and institute that have contributed so much.

Behind that history, though, you'll find a call to action, a clarion note of opportunity. Whatever our history has been, and however much it has prepared us for the future, progress is happening now. Let's keep pushing it.

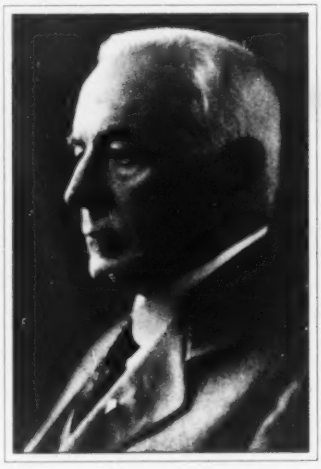
Thomas R. Kuhn
President, Edison Electric Institute


EDISON
ELECTRIC
INSTITUTE
THE FIRST
60
YEARS
BY BARRY CRICKMER

Edison Electric Institute (EEI), the association of America's investor-owned electric companies, was born January 12, 1933, succeeding the National Electric Light Association, which formally ended its existence the following month. Based in New York City, the new organization had 217 member companies by year's end.

From the depths of the depression years through World War II and up to the energy tax debate of today, EEI has helped the electric utility industry successfully meet the challenges of providing reliable, economical electricity to customers across the nation.

As George B. Cortelyou, EEI's first president (the office now called chairman), explained at the Institute's first convention, held in Chicago that June, "one of the principal considerations" leading to the change in organizations was "the feeling which was quite generally held of a necessity to effect a radical simplification in the size and character of the trade association of the electric light and power industry and to make a corresponding curtailment in its cost." Another motivation, he added, was the need "for an organization that had the



GEORGE B. CORTELYOU

power to excercise some degree of discipline over its members with respect to their business practices."

These conditions were a product of the times. In 1928, the Federal Trade Commission (FTC) had begun a widely publicized investigation of utility industry practices. The Commission's reports portrayed the National Electric Light Association (NELA) as an organization devoted primarily to "public relations work and propaganda," which was leading "probably the greatest peace-time propaganda campaign ever conducted by private interests in this country." The resulting blow to the industry's image was compounded when investors lost money on utility holding company stocks in the early months of the Depression.

Many in the industry felt that the FTC's methods were unfair. Bernard F. Weadock, the last managing director of NELA and the first of EEI (the office now called president), was asked by a Senate committee in 1938 if NELA was dissolved as a result of the "facts" revealed by the FTC. He replied: "I would rather say that it was dissolved as a matter of the mis-statement or exaggerations of the Federal Trade Commission...."

Nevertheless, the prevailing industry sentiment was that NELA's reputation, justly or unjustly, had been damaged irreparably. Thus, EEI was set up to be a "pure" trade association, without the lobbying or public relations functions of its forebear. The Institute would promote research, collect and disseminate industry statistics, serve as a forum, be a liaison with other organizations, and require that its members meet certain disclosure standards in their conduct of business.

Because of this reduction in the scope of its functions, the first EEI budget was only 46 percent of the 1932 NELA budget.

Barry Crickmer is manager of editorial services for Edison Electric Institute.

TABLE 1

THEN AND NOW
Profile of the Investor-Owned Electric Utility Industry

Category	1933	1991	% Change
Ultimate customers	22 million	85 million	286
Installed capacity	32 gigawatts	572 gigawatts	1,688
Generation	.75 terawatthours	2.2 terawatthours	193
Largest generating units*	90 megawatts	1,000 megawatts	1,011
Maximum transmission voltage*	287 kilovolts	765 kilovolts	167
Coal needed to generate one kWh*	1.42 pounds	.99 pounds	-30
Average residential revenue per kWh ($1992)	60 cents	8 cents	-87

*general electric power industry

Engineering and Operations

Support for member companies' engineering and operations activities would be the base load of EEI, as it was for NELA. In keeping with its leaner demeanor, however, EEI's organizers chose to emphasize "results of immediate practical usefulness." Thus, the scopes of the power generation, transmission and distribution, and electrical equipment committees were adjusted "to cover the field from the prime sources of energy to the service of lamps, motors and other utilization equipment and to provide for supervision of the various aspects of engineering in this field, not only for design, construction and operation but also for the technical problems of management, economics and research."

Each of these committees consolidated the various responsibilities of two or more of the committees that had existed in NELA's original engineering section. The work of NELA's accident prevention committee, for example, was initially spread among the three committees so each could deal with the safety issues within its jurisdiction. That decision quickly proved to be a mistake, however, because it created "a general impression throughout the country that the EEI was not planning to continue accident prevention activities...." Consequently, in late 1933 the transmission and distribution committee acquired primary responsibility for all safety issues.

Thereafter, EEI's technical committees, made up of member-company volunteers, buckled down to the same kind of work undertaken by their NELA predecessors: evaluating new concepts, procedures, and equipment; reviewing and publishing hundreds of technical papers and experience reports; and holding roundtable sessions where specialists could seek advice from their peers on tough problems. Together, they have contributed significantly to the industry's

progress over the last 60 years. (See Table 1.)

And, over the years, EEI's committee structure continued to change in response to the industry's changing interests and needs. For example, the dispatcher of 1933 had little information to work with and no tools for simulation—purchasing and routing decisions were largely intuitive. In 1993, dispatchers have a wide range of real-time data, with computer modeling ability beyond the dreams of the earlier era. Consequently, today EEI has a computer committee that, among other things, sponsors the Computer Forum, a biennial gathering of experts from the electric utility industry, manufacturing concerns, universities, and research organizations to address developments in the application of computers in the electric power industry.

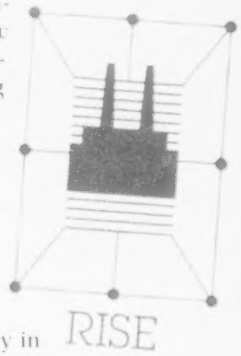
Perhaps no single operations-related program better demonstrates how EEI helps its members work together to improve service while simultaneously reducing electricity prices than the Mutual Assistance Program.

Perhaps no single operations-related program better demonstrates how EEI helps its members work together to improve service while simultaneously reducing electricity prices than the Mutual Assistance Program. Mutual assistance is an old tradition among electric utilities. In fact, at the Institute's fourth convention, EEI president Thomas N. McCarter commented on "the splendid manner in which various public service companies responded to the call for assistance from those more seriously handicapped" when floods devastated parts of the East in the winter of 1936. And they still respond in a "splendid manner." When Hurricane Andrew ripped into Florida and Louisiana in 1992, seven companies sent repair crews to Florida, and seven sent crews to Louisiana. One, Alabama Power, joined both rescue efforts.

As a practical matter, however, important questions arise when crews from one company try to operate in the territory of another: Who do the visiting crews report to? what are the key differences in equipment and procedure? whose insurance covers an accident?

To provide answers to such questions, in 1964 EEI's legal and insurance committee developed "Suggested Governing Principles Covering Emergency Assistance Arrangements" in response to a request from the transmission and distribution committee. It serves as a model agreement that can be adopted by requesting and responding companies at the time aid is sought.

The next step was creation of the EEI Mutual Assistance Roster. It lists companies that have agreed in advance to help one another under the terms of the governing principles and provides the basic information on each company needed by an assisting company's crews.



And the work goes on. Since 1987, disaster recovery efforts have been aided greatly by EEI's RISE (Rapid Information System Exchange) electronic bulletin board. It helps companies to locate equipment quickly in emergencies and also serves as a clearinghouse for excess inventory. And just last year, after five years of effort by EEI and its members, a final roadblock to efficient cooperation in emergencies fell when the Federal Highway Administration agreed to exempt electric utility companies doing business in only one state and responding to an emergency in another from maintaining the detailed driver qualification files required of interstate companies.

Marketing

Although there was to be no EEI advertising or public relations program, the new association immediately decided to support two existing promotional organizations jointly sponsored by utilities and manufacturers: the Electric Refrigeration Bureau and the National Electric Cookery Council. These were years when the industry aggressively sought to expand its share of the end-use energy market, for power generation was a declining-cost business—exploding economies of scale meant that the more electricity sold, the less its per-unit cost. No one wanted to lose momentum.

In the fall of 1933, EEI's sales committee launched a promotional campaign for lighting. The slogan selected was "Better Light—Better Sight" (BLBS). The success of that activity led to the creation in 1934 of the Better Light—Better Sight Bureau, another co-operative promotional organization.

The BLBS push for adequate lighting levels began with the home, then moved successively to the office, the factory, the school, and the highway. Looking back on the first five years of the program, the Bureau's first chairman observed that "the amazing thing is the spread of this gospel into every nook and cranny of the United States and its adoption in most foreign countries."

The program continued until 1979, by which time soaring fuel costs and interest rates combined with other factors to transform the industry into a rising-cost one. As a result, conservation efforts began to take precedence over load-building activities.

The proliferation of load-building programs during those earlier decades—the Electric Water Systems Council, the Modern Kitchen Bureau, the Commercial Electric Cooking Council, and others—had furthered a political objective as well as an economic one. At the time, investor-owned electric companies were being accused of charging excessively high rates. One of the justifications for federal investment in large public power projects such as the Tennessee Valley Authority (TVA) was to provide "yardsticks" for measuring private-sector prices.

TVA had substantial cost-of-money and tax advantages (and still does), but the industry remained confident of its ability to beat the competition. As the chairman of EEI's sales committee put it in 1934: "We...feel that we can withstand successfully comparisons with Governmental yardsticks of average residential rates provided we can build load as fast as, or faster than, the [TVA]," so that rates can be lowered.

And they were right. The success of those first marketing efforts was remarkable: In 1937, although national income was 14 percent below its pre-Depression high, utilities had managed to increase average residential electricity consumption 67 percent while cutting the average rate more than 30 percent.

Still, as a response to continued public sentiment favoring public ownership of the industry, a national advertising "experiment" (many still remembered NELA's "propaganda" brand) was begun in 1941 by 52 operating companies. The program's three objectives were "to win friends, convince people a good job had been done, and to show that no one else could do a better job than private industry." By 1946, 170 companies were participating in this "Advertising Group." In addition to newspapers and magazines, the Group sponsored a Sunday radio program, "The Electric Hour," on the CBS network. The Advertising Group became institutionalized as the Electric Companies Advertising Program.

Whether from lower rates, industry advertising, or both, the percentage of the public favoring private ownership of electric utilities rose (according to Gallup surveys) from 29 in 1937 to 64 in 1946. But the battle concerning TVA's growth, revenue-bond financing, government power marketing agencies, and increased pressure from the Rural Electrification Administration's generating and transmission co-ops continued. For instance, one marketing salvo at which the Institute's members were particularly incensed was a pamphlet published in 1948 by the American Public Power Association that asserted that public power producers provided lower-cost service, paid more in taxes, and operated more efficiently than investor-owned utilities.

Later that same year, EEI's board of directors wanted to expand the public relations effort, authorizing the formation of an external Public Information Program "to collect, verify, and distribute to member companies facts...for informing the people...on subjects of importance to the industry and the public [and] to refute misinformation contained in biased utterances of many proponents of government ownership."

But, of course, not all marketing efforts focused on the question of ownership. In 1956, "Live Better...Electrically" (LBE) was the theme adopted for industry promotional efforts. It started as a joint marketing program, with manufacturers and utilities using the theme in their advertising and EEI providing ideas and materials. The "Gold

Medallion Home" symbol for all-electric homes was created under this program in 1958 for use by home builders who met standards set by the local electric company.

Although LBE was successful, a decline in the growth rate of electricity consumption and increasing competition from natural gas stimulated interest in a higher-powered marketing effort. EEI's commercial division executive committee appointed a special task committee headed by George Ousler, a vice president of Duquesne Light Company, to investigate "ways and means of developing a nationwide industry program to sell our customers the LBE story."

The Ousler committee recommended early in 1958 that EEI itself sponsor, administer, and finance a core program of national advertising and promotion—something the Institute had never done before. The board approved that recommendation at the 26th annual convention, and the program went forward in 1959, retaining the LBE theme. In the first year, ads ran in magazines and on television. Television advertising was discontinued in 1960, because magazines proved more cost-effective. The program, funded by voluntary contributions, continued for more than 10 years.

Meanwhile, many other national industry-sponsored marketing programs were born. To better coordinate these efforts, in 1972 EEI created a subsidiary organization, the Electric Energy Association (EEA), "to serve the marketing needs of the industry." It assumed the activities formerly conducted by the Electric Heating Association, EEI's own marketing division, the LBE Program, the BLBS Bureau, the Electric Vehicle Council, and the Electrification Council.

Finally, in 1975, the Electric Companies Advertising Program, the Public Information Program, and EEA were merged into EEI, although the Institute's board chose to maintain separate funding. At first, EEI called this conglomeration the National Advertising Program—today, it's known as the Media Communication Fund.

Reflecting on these changes in 1976, EEI president W. Donham Crawford observed that "more and more of our destiny is determined in Washington and is affected importantly by the media... Therefore, we have moved toward the kind of organization needed to have a more effective voice at the national level."

Government Relations

Although the Institute's founders had not wanted it to engage in day-to-day government relations work, the industry soon found an urgent need for policy direction and turned to EEI. The first challenge was the Public Utility Holding Company Act of 1935 (PUHCA). This sweeping legislation, promoted as a way to kill off utility holding companies, stunned executives unaccustomed to extensive federal intervention in business practices. In addition to PUHCA, the industry was upset by the prospect of competition from federal power projects and by government grants and loans to municipal electric systems.

In 1935 the Institute retained lawyers to test the constitutionality of these actions. EEI president Thomas N. McCarter explained: "The Edison Electric Institute is not a political organization.... When, however, the crisis...became apparent, believing that the whole plan of the government was unconstitutional and *ultra vires*, it determined that it owed to its membership the obligation to test out these principles of constitutional law."

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Although the industry won some initial victories in court, they did not prove decisive. It was the beginning of a long struggle against federal competition and federal intrusion.

Of course, during World War II, the industry worked closely and cooperatively with the national government. Early in the war, EEI president C.W. Kellogg took a leave of absence and went to Washington to serve on the Defense Commission and the Office of Production Management. In March of 1942, a group of industry CEOs formed the Council of Electric Operating Companies, a temporary organization intended "to assist various governmental agencies responsible for the war effort by coordinating the experience, man-power and equipment of the electric operating companies." At the time, electric utilities were the only important industry not represented in the Capital, a fact which the Council's founders considered a handicap to both the industry and the government. The Council, whose members produced 85 percent of

the nation's electricity, set up offices in Washington and communicated with the industry primarily through EEI.

By 1945, the industry created a new organization, the National Association of Electric Companies (NAEC), to represent its interests in Washington permanently, an arrangement that continued instead for 25 years. By the 1970s—under pressure from a new federal regulatory agenda and escalating fuel costs—the industry had begun seriously considering an EEI-NAEC merger. The boards of the two organizations formed a joint committee to study NAEC-EEI relationships in 1976. It recognized "substantial changes in the kind and amount of contact effort required in Washington," and upon its recommendation, EEI move part of its staff from New York City to the Capital to work more closely with NAEC.

The next year, however, the NAEC board voted for consolidation, and in January 1978 the EEI board concurred, citing "the high priority that governmental affairs in Washington has on the ability of the investor-owned utilities to carry out their numerous tasks." EEI moved its headquarters to Washington in 1979.

World War II

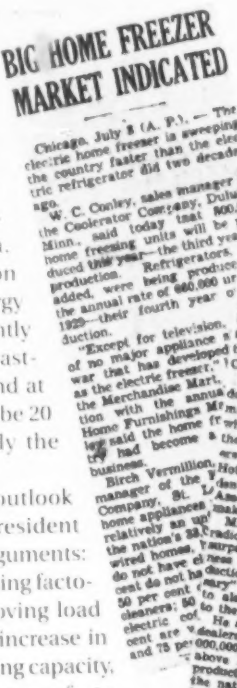
In the late 1930s, as U.S. involvement in World War II looked inevitable, one of the critical questions faced by government planners was whether electric utilities could deliver sufficient power for war production. The Federal Power Commission (FPC, ancestor of the Federal Energy Regulatory Commission) consistently predicted power shortages, forecasting, for example, a level of demand at the end of 1942 that turned out to be 20 percent higher than was actually the case.

EEI, however, assessed the outlook accurately. In 1940, Institute president Kellogg pointed to three basic arguments: War production would cause existing factories to work longer hours, improving load factors without a corresponding increase in peak demand; additional generating capacity, if needed, could be added as fast as new factories could be built; and power could be moved where it was needed through the industry's extensive interconnections. Further, the U.S. had more generating capacity at the time than that of England, France, and Germany combined.

Events proved Kellogg right. From 1939 through 1944, total U.S. electric utility industry sales per year grew 87.3 percent, yet generating capacity increased just 25 percent. The bulk of the difference—42 percent—was due to higher load factors.

When the war ended, the industry could claim with pride that no war-related effort was ever delayed for lack of electricity, full service was maintained to the civilian population, and the average price of electricity was lower than it had been in 1939. The government's postwar "History of the Office of War Utilities," in tribute to the nation's electric companies, notes that "the one industry which was most frequently singled out, before the war, as the weak link in America's ability to produce munitions stands today as the one industry which, through the war, met every requirement placed upon it."

Ironically, it was on postwar demand that nearly everybody made the wrong guess. Electricity demand was expected to plummet as the superheated war economy converted to a more relaxed peacetime pace. In anticipation, EEI's commercial planning committee recommended that the industry catch up on deferred maintenance, become more customer-oriented, and cooperate more closely with electrical equipment manufacturers in national promotions. The Institute also developed sales training courses to help member companies build load.

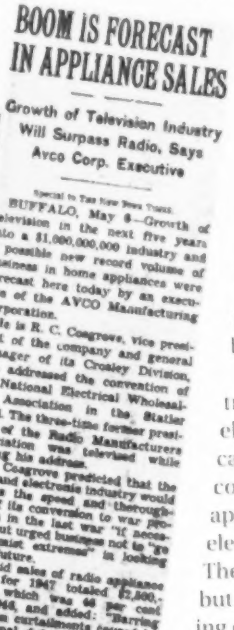

BIG HOME FREEZER MARKET INDICATED

Chicago, July 8 (A. P.). — The electric home freezer is sweeping the country faster than the electric refrigerator did two decades ago.

W. C. Conley, sales manager of the Coolerator Company, Duluth, Minn., said today that 800,000 home freezing units will be produced this year—the third year of production. Refrigerators, added, were being produced at the annual rate of 660,000 units in 1929—their fourth year of production.

"Except for television, there is no major appliance in sight that has developed the demand as the electric freezer," the Merchandise Mart, center of the tion with the annual Home Furnishings Mart, said the home freezer had become a business.

Birch Vermillion, manager of the Company, St. Louis, home appliances relatively sat up the nation's 33,000,000 wired homes, 75 per cent do not have electric refrigerators, 50 per cent have no electric cleaners; 50 per cent are dealers and 75 per cent of the


BOOM IS FORECAST IN APPLIANCE SALES

Growth of Television Industry Will Surpass Radio, Says Avco Corp. Executive

Special to The New York Times.

BUFFALO, May 6.—Growth of television in the next five years into a $1,000,000,000 industry and a possible new record volume of business in home appliances were forecast here today by an executive of the AVCO Manufacturing Corporation.

He is R. C. Cosgrove, vice president of the company and general manager of its Crosley Division, who addressed the convention of the National Electrical Wholesalers Association in the Statler Hotel. The three-time former president of the Radio Manufacturers Association was televised while making his address.

Mr. Cosgrove predicted that the radio and electronic industry would surpass the speed and thoroughness of its conversion to war production in the last war "if necessary" but urged business not to "go to alarmist extremes" in looking to the future.

He said sales of radio appliance dealers for 1947 totaled $2,800,000,000, which was 40 per cent above 1946, and added: "Barring production curtailments caused by the national defense program the improvement should increase this year."

He quoted estimates that 1948 radio receiver production will total at least 14,000,000 sets; that home refrigerator output will be around 4,500,000 units assuming that manufacturers can fulfill production plans.

Atomic Energy

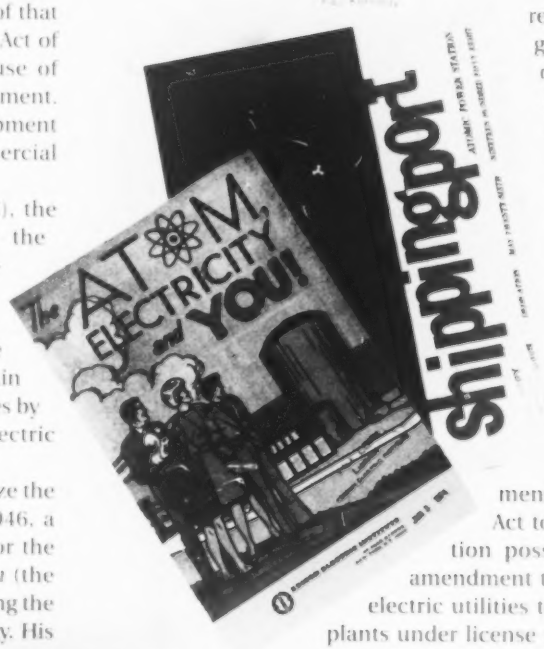
The power of the atom first was harnessed for military purposes in World War II's super-secret Manhattan Project. After the war, the traditions of secrecy and federal control characteristic of that effort were codified in the Atomic Energy Act of 1946, which restricted ownership and use of fissionable materials to the federal government. This obstacle threatened to retard development of nuclear energy for peaceful commercial purposes.

The Atomic Energy Commission (AEC), the federal agency established to oversee the government's vast nuclear operations, favored ending the federal nuclear monopoly to facilitate rapid development of the new energy source. Consequently, the AEC began taking what steps it could within the Act to invite participation in its activities by private-sector companies—especially electric utilities and their suppliers.

Electric utilities were not slow to recognize the nuclear potential. As early as January 1946, a Westinghouse scientist wrote an article for the monthly *Edison Electric Institute Bulletin* (the predecessor of *Electric Perspectives*) assessing the prospects for using this new form of energy. His conclusion: "Atomic power almost assuredly will become a practical power source...." By the EEI convention the following June, the subject was well represented on the program.

In 1952, a special committee on atomic energy was appointed at the EEI presidents' conference. Following its recommendation, EEI's board created a standing committee on atomic power the next year.

In its first report, to the 1953 EEI convention, the committee observed that the industry had more than one motive for an interest in nuclear energy. Not only was uranium a potential fuel, it also was the basis for a new, electricity-intensive extractive industry. The gaseous diffusion plants operated by the AEC to refine uranium ore made it the world's largest single user of electricity. Each plant consumed about 15 billion kilowatthours per year, a demand so great that it had to be supplied by coalitions of utilities, both government and investor-owned.



Later that year, the AEC recommended to the congressional Joint Committee on Atomic Energy that the Act be amended to permit ownership and operation of nuclear power facilities by "groups other than the commission." The Eisenhower administration, promoting "Atoms for Peace," took a similar position. In response, the Joint Committee asked EEI's committee on atomic power for recommendations on changing the Act to make private participation possible. EEI submitted an amendment to enable investor-owned electric utilities to operate nuclear power plants under license from the AEC. Thanks to these efforts, the Atomic Energy Act of 1954 permitted private ownership of nuclear power facilities.

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Even before the Act could be changed, however, a number of utilities bid competitively on an AEC contract to build an electric power plant using nuclear energy. The Duquesne Light Company of Pittsburgh was the winner, and ground was broken September 6, 1954, at Shippingport, PA, for the first full-scale nuclear power plant in the United States.

By 1956, as part of a national effort to encourage the peaceful use of nuclear energy to produce electricity, 11 co-funded demonstration plants were being built and operated by utility consortiums. And EEI was cooperating with the AEC on the evaluation of reactor types.

Years later, in 1973, the Joint Committee on Atomic Energy was dissolved, and its responsibilities were dispersed to other committees. To cope with the additional government-relations burden that change imposed, EEI helped the industry create the American Nuclear Energy Council, whose purpose is to provide nuclear-related information to the federal sector. EEI also was instrumental in the founding of two other key organizations serving the nuclear industry

following the 1979 accident at Three Mile Island: the Institute of Nuclear Power Operations, created so that the industry might "set and police its own standards of excellence"; and the U.S. Council for Energy Awareness, which educates the public on the importance of nuclear power.

The 1970s in general were rough years for the industry. The fuel price increases resulting from two interruptions in petroleum shipments from the Middle East decreased energy use and kindled an interest in conservation, leaving the industry with an excess of generating capacity. Orders for new baseload plants—nuclear and coal—were cancelled. And nuclear plants nearing completion became entangled in regulatory investigations of whether the investment had been a prudent one. As a result, no new nuclear plants have been ordered since 1978, even though nuclear energy offers some attractive environmental benefits in comparison to other fuels.

To end this stalemate, the industry turned to the Nuclear Power Oversight Committee (NPOC), which evolved from a committee formed in 1979 by EEI and seven other national organizations to serve as the nuclear industry's highest policy-making body. In 1990, NPOC developed a comprehensive strategic plan for establishing the conditions needed for building advanced nuclear energy plants in the 1990s. That plan assigns responsibilities to different industry organizations for meeting the 14 conditions that will permit a plant or-der. EEI is responsible for 5 of the 14: clarification of ownership and financing, state economic regulatory issues, nuclear fuel supply issues, high-level radioactive waste disposal, and low-level radioactive waste disposal.

Research

Promotion of research was a fundamental EEI goal at its founding. For more than 40 years, technical papers filled the pages of the *EEI Bulletin*. As the industry became more complex technologically, the Institute began to encourage research in certain directions, contributing to projects undertaken by other organizations and sponsoring some projects directly. Such projects were chosen by the appropriate standing committee, screened by a research projects committee, and submitted for board approval. Those approved were administered by a task force of the standing committee. The scope of the research was far-ranging. For example, EEI sponsored research on air pollution and on solar-assisted heat pumps in the 1950s, and water pollution and electric vehicles in the 1960s, well before the unofficial birth of the environmental movement on Earth Day in 1970. Even the cardiac defibrillator, reviving stopped hearts in many a medical drama, was developed with a grant from EEI.

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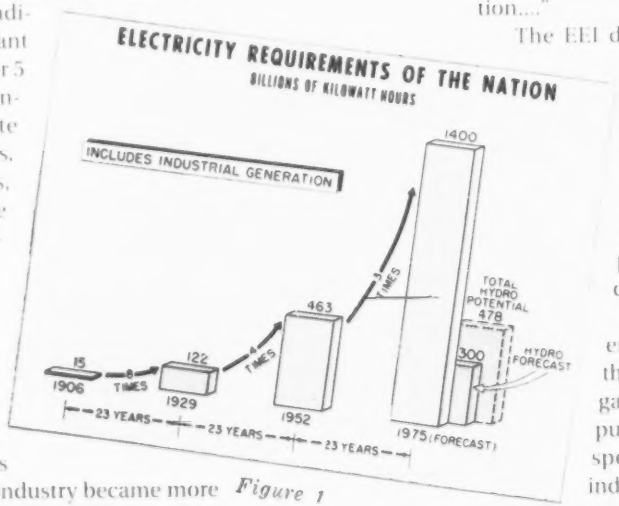


Figure 1

Despite this record, in the 1960s there was a feeling both inside and outside the industry that not enough resources were being devoted to research. In 1963, the chairman of the Federal Power Commission (FPC) complained in a speech to EEI that the industry was "not carrying on an adequate research program," and recommended "a permanent industry-wide research organization...."

The EEI direct annual contribution to research programs grew from $600,000 in 1961 to $6.8 million in 1969. According to FPC figures, however, total investor-owned electric utility R&D expenditures in 1969 amounted to only 0.25 percent of revenues, compared to 2.3 percent in the communications industry and 3.7 percent in chemicals.

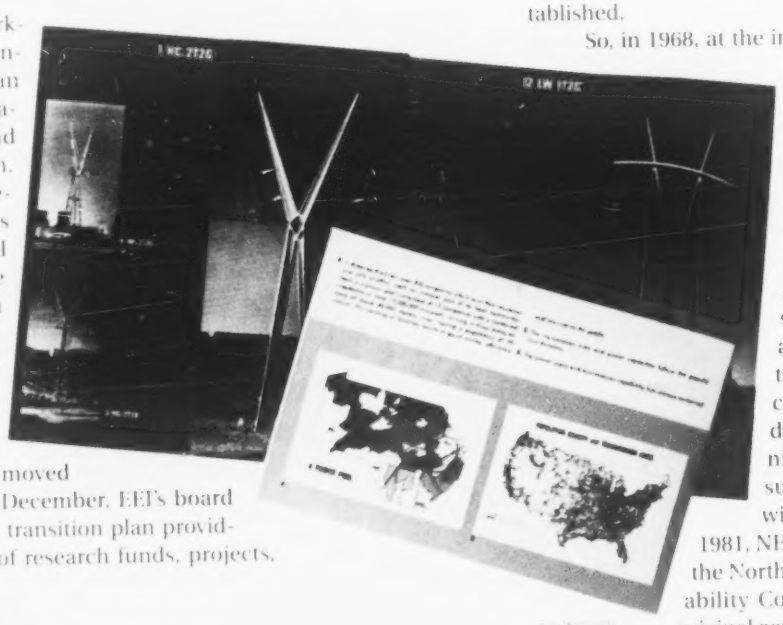
Thus, as a result of a 1965 conference sponsored by the FPC in 1965, the Electric Research Council was organized. Its purpose was to enable public and investor-owned utilities to sponsor research jointly. But the industry's research needs continued to grow, and in 1971 a Council task force recommended "a full-time organization charged with the development of research plans and the vigorous implementation of programs."

Shortly after the Council's report was issued, Senators Warren Magnuson of Washington and

Ernest Hollings of South Carolina introduced legislation to establish a "Federal Power Research and Development Board" funded by a 0.15 mill per kilowatthour tax on all electric utilities. This proposal was withdrawn after EEI's chairman, Shearon Harris of Carolina Power & Light Company, told the Senate Commerce Committee that the industry was organizing and financing an expanded R&D program on a voluntary basis.

At its December 1971 meeting, EEI's board of directors approved guidelines for a three-year transition program to a new financing mechanism. It called for the investor-owned segment, through EEI, to increase cooperative R&D funding from about $29 million a year in 1972 to $137 million in 1974.

The next year, working through EEI, the industry established an entirely new organization to finance and conduct its research. The Electric Power Research Institute was incorporated in April 1972, succeeding the Electric Research Council. EPRI—with Chauncey Starr as its first president—was housed in EEI's New York offices until September, when it moved to Palo Alto, CA. By December, EEI's board had approved a new transition plan providing for the transfer of research funds, projects, and staff to EPRI.



Transmission Reliability

When EEI was born, the industry already was served by an extensive transmission network. As interconnections became more complex and more widespread, electric companies formed regional organizations to coordinate bulk power movements. And through its committee system, the Institute provided a forum for discussing transmission-related issues and supported research on transmission technology.

Although the industry's reliability record was very good—perhaps *because* of that—the Northeast blackout of 1965 focused national attention on reliability. In response to public demands for safeguards, the EEI board of directors created a new division in 1966 to facilitate discussions of power-systems coordination at management, planning, and operational levels. The Institute also took the lead in opening the regional organizations to all users of the grid, whether investor-owned or not.

The next year, the FPC sought additional statutory authority for "enhancing the reliability of bulk power supply...by strengthening existing and establishing new mechanisms for coordination in the electric utility industry..." A Senate bill was introduced to provide it. Also in 1967, largely at the insistence of federal agencies, the nation's private and public electric systems were tied together in a coast-to-coast transmission grid. It proved impossible to control, and the tie was opened less than six months after it had been established.

So, in 1968, at the initiative of EEI's board, the industry formed a new organization—the National Electric Reliability Council (NERC)—to promote the reliability and adequacy of the bulk power supply in North America's electric utility systems. Its members are the nine (12, initially) regional reliability councils. The Senate dropped the bill in recognition of the industry's successful effort to deal with reliability issues. In 1981, NERC changed its name to the North American Electric Reliability Council (but retained its original acronym).

Human Resources

From the beginning, the EEI sales committee provided various forms of training and other assistance to company salesmen, and by its very nature, the committee's structure provided opportunities for utility professionals to learn from each other. But the Institute also sponsored more formal professional development programs. For example, through an informal committee representing the electric, gas, and telephone industries, EEI participated in an executive development program held in 1951 at the University of Michigan. Fifty-seven executives attended, 29 of them from electric companies.

The prestigious EEI Executive Leadership Program (long known as the "Hershey program" for its quarters in Hershey, PA) was created specifically for upper management people by a special subcommittee of the industrial relations committee and was designed to provide a comprehensive course emphasizing the application of management skills to a wide range of electric utility problems. The first one was held in 1968, and since then, more than 700 people from 135 companies in the U.S. and abroad have participated. Nearly 60 of its graduates became industry presidents, CEOs, and chairmen.

The human-resource challenges weren't simply internal, however. During the early 1970s, the federal government criticized employers in general for the apparent lack of positive efforts toward achieving equal employment opportunities for minorities, women, and the disabled. The electric utility industry was one of those identified by the Equal Employment Opportunity Commission as a major industry which had fallen behind in this area.

Although the industry felt that this condemnation was not fully deserved, EEI's affirmative action committee intensified its efforts to further equal employment opportunity and affirmative action among member companies, sponsoring its first Affirmative Action Seminar in 1973. Under the committee's leadership, the industry initiated scores of programs.

In the mid-1970s, an ad-hoc group of EEI's member companies began discussing the need for bias-free employment screening tests to help the industry identify the most qualified job applicants. This group became the EEI personnel research task force, which developed the Plant Operator Selection System. It was ready for use in 1981—the first of the nine EEI test batteries available today. The EEI Testing Program is separately funded and since 1992 has been open to all industry employers, regardless of type of ownership or EEI membership status.

In 1982, EEI became one of the first three organizations to sign the NAACP's Declaration of Fair Share Principles, which set out tenets for increasing philanthropic goals, utility purchasing activites among minority-owned businesses, and minority hiring. Ten years later, the NAACP presented the Institute its Fair Share Tenth Anniversary Signatory Award in recognition of such EEI activities as the Minority Business Development Program, the annual Minority Business Trade Show, the annual Minority Vendor Trade Show, and the Utility Contacts Directory for Minority Business Development.

In 1983, the affirmative action committee's subcommittee on compliance implemented an annual industry awards program to honor companies exemplifying affirmative-action excellence. As a result, EEI was the first trade association to receive the Award for Exemplary Voluntary Affirmative Action Efforts, which was presented in October 1983 by the director of the Office of Federal Contract Compliance Programs.

More recently, in 1991, EEI signed an affirmative-action agreement with the Hispanic Association on Corporate Responsibility, the first national trade association to do so. It encourages the Institute's member companies to expand their relationships with the Hispanic community in many ways.

The prestigious EEI Executive Leadership Program was designed to provide a comprehensive course emphasizing the application of management skills to a wide range of electric utility problems.

The Next 60 Years

Throughout the history of the electric utility industry, new challenges have emerged as old ones were surmounted—technical, political, economic, and more. That process is sure to continue, and you could probably tick off as many new challenges in the immediate future as surmounted ones in the immediate past. The industry in 2053 may be as different from the industry of today as 1993 is from 1933. It is safe to predict, however, that the people of 2053 still will require a reliable, safe, economical, and environmentally responsible electricity supply, that someone will have the primary responsibility for providing it, and that those companies will continue to be served by a trade association responsive to their needs and adaptable to the temper of the times.

An association like EEI. ◆

EMF
THE PROCESS OF DIALOGUE

BY GENE POKORNY

WITH GREAT SPEED, EMF HAS MOVED FROM BACKGROUND TO FOREGROUND IN THE PUBLIC DEBATE. WHAT DO CUSTOMERS THINK? HOW SHOULD UTILITIES RESPOND?

However they are framed, the questions surrounding electric and magnetic fields (EMF) have created a major issue for electric utilities, customers, regulators, legislators, and scientists. In a number of ways during the last several months, the issue has been highlighted and brought to the fore:

- *The Distinguished Gentleman*, a movie released in December and starring Eddie Murphy, used EMF health issues as a major plot vehicle—Murphy fights utility interests after he meets the mother of a girl who's gotten cancer, allegedly from power lines. Television entertainment—ABC's "Civil Wars," CBS's "Northern Exposure," NBC's "Sisters"—also featured the issue, even if only in passing dialogue.
- In December, *The New Yorker* published "The Cancer at Slater School," by Paul Brodeur, which alleged that transmission lines are giving cancer to students, teachers, and employees at a Fresno, California, school and that the California health department and utilities are trying to cover it up.
- In the first quarter of 1993, *USA Weekend* published "Is My Electric Blanket Killing Me?" in an insert carried by many other newspapers around the country; the *Wall Street Journal* ran a front-page story on potential cancer lawsuits faced by utilities and other businesses; *Science*, *Discover*, and *Fortune* magazines (among others) published stories on the debate.
- Likewise, CBS's *Street Stories*, ABC's *Good Morning America* and *PrimeTime Live*, and CNN's *Larry King Live* featured reports and discussions on EMF's potential health effects; National Public Radio's *All Things Considered* has aired a 15-minute analysis of the issue, and its *Talk of the Nation* spent an hour on the topic.

And there's more to come. While the utility industry has been communicating openly about EMF, has supported efforts to ensure the health of its customers, and has actively pursued research on possible EMF health effects and field management, different stakeholders maintain varying views on what is biased and what is objective, on what is and isn't conclusive. Consequently, what was once a discussion occurring primarily in academia and R&D centers has become a full-blown issue in the public consciousness.

Although a complete understanding of EMF is still to come, some things are already clear. First, more scientific re-

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Roger Ferry / Ford

In the last few months, the media have reported on the EMF issue a great deal. There's more to come.

search is an indispensable need. Second, opinion research is necessary to uncover customers' understanding of the issues involved, their concerns, and their needs and preferences for EMF information. And third, as the issue impinges on more aspects of an electric utility's activities, the company must continue to maintain a constructive response to the concerns of its customers.

The Fuel for Public Opinion

In recent years, some scientific studies have tried to gauge the possible association between human exposure to EMF and adverse health effects. Several epidemiology studies have been undertaken since 1979. Some studies have reported a correlation between estimated measures of exposure and certain types of leukemia and cancer; some show no correlation.

To a large extent, what has recently propelled EMF up the public-policy list is a 1992 study by researchers at Stockholm's Karolinska Institute. The residential study examined everyone who lived near Swedish transmission lines from 1960 to 1985, and it claims to have found a correlation between estimated magnetic fields from the lines and leukemia in children.

Other studies since then have come up with negative results, and researchers generally agree that more research is needed. The Energy Policy Act of 1992, for instance, signed into law at the end of October, established a five-year, $65-million, federal/nonfederal EMF research and public-information dissemination program; the electric utility industry has volunteered to provide $21 million to the effort.

The variables of research are wide-ranging, and they intensify the complexity of the EMF issue—how do other environmental factors affect results? how do duration, intensity, and proximity of EMF exposure correlate? if there are risks, at what level do they become unacceptable?

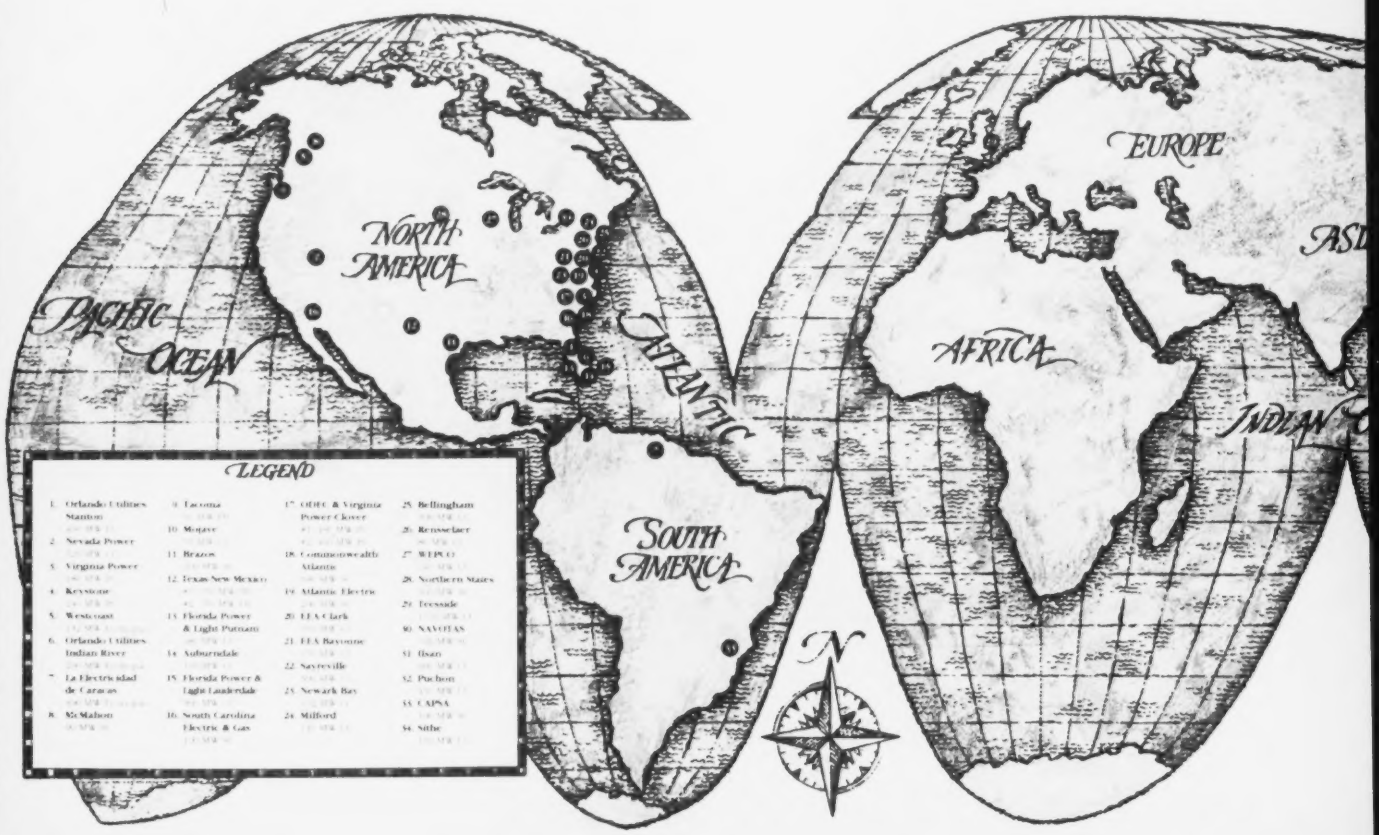
Since 1975, the electric utility industry, through the Electric Power Research Institute, has dedicated more than $65 million to EMF research

projects. Individual utilities fund their own programs as well. Much of this research focuses on ways to control exposure, but given the inconclusive nature of the epidemiological studies, it is difficult to gauge whether a particular reduction action is a benefit or not. You can find out what the cost of an action is, and you can measure the difficulty of accomplishing it, but without a health-effect coefficient, the mitigation equation is incomplete.

Still, EMF is an important issue for many customers, and utilities have established a wide range of customer service, communications, and educational programs designed to respond to EMF concerns. According to a November 1992 Edison Electric Institute (EEI) survey of electric utilities concerning their EMF activities, nearly all companies (91 of 94) conduct free magnetic field measurements at homes, schools, industrial sites, offices, and other workplaces. To help people understand EMF, all the measuring utilities provide literature, and a good 90 percent of them do comparative readings, showing the differences among appliances and how variable a field is depending on the distance from its source. Two-thirds of those utilities allow the customer to use the gaussmeter (which measures EMF in milligauss). Several companies instruct their employees to provide general explanations of EMF; they also make available reports and resource bibliographies. A fifth of all the surveyed utilities have a video on EMF, which some utilities may show during the site visit.

To guide these various activities, 84 percent of the responding utilities said they had, were revising, or were developing an EMF policy statement.

In the 1992 study, 54 percent of the companies reported a surge of EMF-exposure inquiries directly attributed to press coverage—particularly the initial release of the Swedish studies, along with subsequent magazine articles and national media coverage. The remaining inquiries focused on concern over specific utility construction projects, right-of-way purchases, and local television programming. Most of the utilities said that they received between one to 10 calls a month from customers about EMF in 1992. Anecdotal evidence from utilities since the first of the year, however, suggests that some companies have fielded as many as 60 calls a week. In fact, it appears that some individual electric utilities filled more requests for EMF



information in January than they did in all of 1992.

The Public Reaction

Public awareness of EMF continues to grow.

That growth is dramatically revealed in an annual series of public opinion surveys conducted since 1987 by Cambridge Reports/Research International for EEI. Each survey is based on interviews with 1,250 Americans selected to represent the adult U.S. population. For the last four years, the number reporting awareness of the EMF issue has grown steadily at 4 to 5 percentage points a year: In 1989, 31 percent had heard or read something about the possible health effects of EMF; in 1990, it was 36 percent; in 1991, 40 percent; in 1992, 45 percent.

Only 13 percent of Americans report that someone in the household has acted to reduce EMF.

In a February 1993 survey, however, the number aware jumps to 63 percent. (See Table 1, Question 1.) Much of this jump may be attributed to recent widespread media attention.

Despite that dramatic increase over the last few years, the public has a continuing uncertainty about the specifics of the issue and what should be done.

In 1987, for example, 42 percent of Americans said the scientific community knows "a great deal" or "a fair amount" about EMF and its possible effects. By 1992, that number grew very little, to 47 percent. (Question 2.)

Similarly, 18 percent in 1987 felt that EMF presented a "very" or "somewhat serious threat" to their personal health and safety, while 53 percent characterized the threat as "not too serious" or

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TABLE 1

EMF IN GENERAL: CUSTOMER OPINIONS
(percentage of respondents)

Question 1: Electric and magnetic fields surround every wire that carries electric power, from household appliances to overhead power lines. Have you heard or read anything recently about the possible health or environmental effects of electric and magnetic fields?

	2/93	11/92	11/91	11/90	11/89	11/88	11/87
Yes, have heard	63	45	40	36	31	29	31
Not sure	0	1	2	2	1	9	8
No, have not heard	36	53	58	62	68	62	60

Question 2: How about you, how do the experts in the community's current understanding of the problems—if any—associated with electric transmission and distribution lines and the effects of those lines on people, animals, and plants. Would you say the scientific community knows a great deal about this issue, a fair amount about it, a little about it, or not much at all about it?

	11/92	11/91	11/90	11/89	11/88	11/87
A great deal	12	13	13	17	9	10
A fair amount	35	34	34	39	31	32
A little	26	27	26	24	19	18
Not much at all	21	21	20	15	19	19
Don't know	6	5	7	5	22	20

Question 3: Every wire that carries electricity produces electric and magnetic fields. In general, how much of a threat do you consider electric and magnetic fields. Do you consider them a very serious threat, a somewhat serious threat, not too serious a threat, or not a threat at all?

	2/93	11/92	11/91	11/90	11/89	11/88	11/87
Very serious	5	10	7	5	7	5	3
Somewhat serious	22	28	28	21	22	17	15
Not too serious	42	39	40	41	40	30	30
Not at all	22	15	17	26	24	19	23
Don't know	9	7	7	6	7	28	28

Question 4: Which of the following views about electric and magnetic fields is closer to your own?

Before acting to regulate electric and magnetic fields, we should increase out research efforts to find out exactly what health risks there may be from electric and magnetic fields.

	11/92	11/91	11/90	11/89	11/88	11/87
Agree	69	68	71	75	66	68
Don't know	8	10	11	10	23	21

We should immediately take strong action to reduce exposure to electric and magnetic fields even if it means higher electric rates.

	11/92	11/91	11/90	11/89	11/88	11/87
Agree	23	22	18	15	11	11

Note: 1993 data is not available for questions 2 and 4.

"not a threat at all." By 1992, 38 percent believed EMF presented a "very" to "somewhat serious threat," but a majority (55 percent) still viewed the threat to be "not too serious" or "not a threat at all." (Question 3.)

That was the state of the opinion research at the end of 1992, just as the enormous amount of media attention was beginning to give prominence to the issue. To many observers, such constant attention on an issue should lead not only to a jump in awareness but also to an increase in the number of people willing to make judgments about specifics. The February 1993 numbers suggest the opposite trend on this question about the threat of EMF. In February, 27 percent considered EMF a "very" or "somewhat serious threat," and 64 percent thought that EMF was "not too serious a threat" or "no threat at all."

Here's another pertinent set of figures. In 1987, 68 percent of Americans supported the view that "before acting to regulate EMF, we should increase out research efforts to find out exactly what health risks there may be. . . ." (Question 4.) In 1992, that view was supported by 69 percent. The contrary view, however, that "we should immediately take strong action to reduce exposure to EMF even if it means higher electric rates" was supported by 11 percent of Americans in 1987 and 23 percent in 1992.

What's to be made of all these numbers? Overall general awareness of EMF is clearly rising, but a rush to judgment on the public's part is not occurring yet, though the November 1992 responses to the "threat of EMF" question does show a flare-up that subsided by February. As you can see from Table 1, in the last three questions, the "don't know" responses are down dramatically and have moved to other answers. This is a typical pattern in opinion research that monitors the lifecycle of public issues. What is unusual in the case of EMF, however, is the relatively restrained movement to the more extreme positions in the questions: "a

Transmission facilities are often the touchstone for customer awareness of EMF.

great deal" is known about EMF; EMF is "a very serious threat"; and "immediately take strong action."

This slower rush to judgment on the EMF issue seems based, to a large extent, on the pervasiveness of electricity in contemporary life—its ubiquitousness and essential role. In addition, virtually all Americans know and accept the fact that electricity is and can be dangerous if not used properly. Americans assume that many things they buy are risk-free, but they do not view electricity that way. Rather, their paradigm for thinking about electricity is more complex. It forces their consideration of the EMF issue in shades of gray, not the stark black-and-white terms that have enveloped other policy issues in the health and safety area in recent years.

Bringing the Issue Home

The paradigm used by most Americans for thinking about electricity and EMF considers both the risks and benefits of electricity and their trade-offs. Consumers want electricity to be as safe as possible, but they also want it to be affordable and reliable. While slowing down an overall rush to judgment, this paradigm, in an ironic way, may well be heightening the extent and intensity of citizen interests and actions about EMF at the local, site-specific level.

The "old" in the way of household electrical wiring and appliances and community electrical facilities is by and large taken for granted. Most consumers have a comfort level with these installations and a time-validated acceptance of them. Most appear unwilling to alter their established ways of using electricity. Despite the increased attention on EMF in the media, only 13 percent of Americans in the February 1993 Cambridge Reports survey, for example, indicated they had taken any steps in their household to reduce EMF exposure. (See Question 1, Table 2.)

But because the "old" is known and

acceptable, for many Americans the "new" seems almost inevitably to become the focus of their rising EMF awareness and concern. This is particularly the case when the "new" is a proposed, highly visible transmission or distribution project.

A series of questions from the public opinion surveys done for EEI highlight the extent of this concern with "new" electrical facilities at the local level. Asked how worried they would be about three concerns if high-voltage transmission lines were placed adjacent to or on their property, approximately three-fifths of all Americans say they would be "extremely worried" (points 6 and 7 on the 1-7 scale) about a decline in their property's value (63 percent), a worsening of their health (56 percent), and deterioration in the aesthetic value of their property (59 percent). (Questions 2-4.) In all three cases, these "extremely worried" segments are approximately twice the size they were four years ago.

Actual experience among utilities confirms this opinion research data. According to EEI's 1992 study of EMF activities at 94 utilities, most customer calls and inquiries to utilities about EMF dealt with utility construction, local siting procedures, and proximity to electrical substations. Many companies also indicated a rise in 1992 over 1991 of calls and inquiries from municipal officials—mostly about new siting procedures. Sixty-four percent of the utilities in the 1992 study reported that concern over property values was a key factor in the EMF calls and inquiries they handled. And finally, in 1992, electric companies in the survey said that EMF concerns—once they were broached in transmission, distribution, and substation proceedings concerning a reported total of 201 proposed plans—delayed, changed, or stopped about half (92) of those plans.

Proposed new T&D installations for many utilities have, in essence, become a kind of lightning rod for their customers' growing EMF awareness and concerns. The very tolerance and

TABLE 2

EMF NEARER TO HOME: CUSTOMER OPINIONS
(percentage of respondents)

Question 1: Have you or has anybody in your household taken steps to reduce exposure to electric and magnetic fields?

	2/93	11/92
Yes	13	12
Not sure	1	3
No	86	85

Questions 2-4: Let's assume that high-voltage transmission lines were place adjacent to or on your property. Think of a scale from 1 to 7, where 1 means "not worried at all" and "7" means "extremely worried." Now I'm going to read you a list of several concerns some people could have when high-voltage transmission lines run adjacent to or through their property. As I read each one, please tell me how worried you would be about each concern. The more worried you would be, the higher the number you would give it.

Question 2: A Decline in the Value of Your Property

	11/92	11/91	11/90	11/89	11/88
7—extremely worried	47	37	38	41	16
6	16	14	14	13	13
5	15	17	15	13	18
4	8	9	10	8	15
3	3	7	8	8	9
2	2	5	5	5	7
1—not worried at all	6	10	10	10	15
Don't know	2	1	2	1	7

Question 3: A Worsening of Your Health

	11/92	11/91	11/90	11/89	11/88
7—extremely worried	44	34	33	34	15
6	12	12	8	9	10
5	14	15	13	12	12
4	8	10	10	10	19
3	5	9	8	11	11
2	5	6	9	9	9
1—not worried at all	9	12	15	12	15
Don't know	2	2	3	2	9

Question 4: A Deterioration in the Aesthetic Value of Your Property

	11/92	11/91	11/90	11/89	11/88
7—extremely worried	44	31	37	38	17
6	15	13	12	13	14
5	16	19	18	15	18
4	8	11	9	11	14
3	5	7	9	7	10
2	3	5	5	4	6
1—not worried at all	7	10	8	9	12
Don't know	2	4	3	2	9

Note: 1993 data is not available for questions 2-4.

acceptance most consumers give to "old" facilities may only serve to increase their sensitivities and expectations for "new" facilities once they are proposed. To characterize EMF-based opposition to new T&D facilities as simply just another example of the NIMBY (not-in-my-back-yard) syndrome misses this subtlety of what is taking place in consumer thinking and behavior on EMF.

But given all this, how then should utilities respond?

While the full answers to this question inevitably must depend on the particulars of the service territory, I can offer a few general observations. My observations are based on my knowledge of the public-opinion research and a review of experiences that utilities around the country have had as they have responded to EMF issues in their communities.

Substance

Utility EMF activities and communications work better if they are in harmony with the basic ways consumers already think about electricity. Discussing EMF as an electrical safety issue is one way to achieve this harmony. Through words, analogies, and metaphors, it can be placed within the broader context of all the other electrical safety issues that utilities and their customers have confronted and dealt with by working together over the years. Consumers are more tolerant of a utility explaining what it doesn't know about EMF, if it also spends time delineating what it does know, and (based on the current state of knowledge) what it is doing, and what customers can do themselves, to lessen any possible risks.

Scientific uncertainty about EMF and its possible health effects is a fact. Most consumers can accept that fact, for living with uncertainty is not an uncommon experience. Yet consumers also know they make decisions in uncertainty, based on their best information. They expect their utility to do likewise and not to use uncertainty about EMF as an excuse for inaction and avoidance of responsibility.

Style

For many consumers, the style of utility EMF activities is critical in determining how they feel about the issue itself and rate their utility's performance on it. While many consumers may not feel competent to judge the specific scientific facts and arguments in the EMF debate, virtually all con-

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sumers do feel competent to judge whether a utility, as it deals with EMF issues, is open, honest, and responsive. Utilities only hurt themselves in the long run if by their actions they create perceptions among customers that they are hiding information or avoiding responsibility for the service they sell and its possible effects. The efficacy of EMF activities is dramatically enhanced if their tone is one of respect and understanding for people's legitimate EMF concerns and anxieties.

Since so many of the "facts" in the EMF debate are by nature so very complex, esoteric, and even alien to most people's daily experience, a special challenge faces utilities as they try to discuss these "facts" with customers. There are books on how to communicate science effectively with lay audiences, and much can be gained from them. A few words of advice:

- minimize scientific jargon;
- use common analogies;
- take the time to provide context and background; and
- perhaps most important of all, accept the fact that the scientific "facts" about EMF are best used to promote understanding, not to persuade.

Process

In the face of the scientific uncertainty about EMF and the diversity of customer concerns and understanding about the issue, utilities may be tempted to do nothing or merely give "the scientific facts" and be done with it. But the overriding "fact" about EMF is that many people continue to have questions. Given this, utilities cannot tell their customers not to worry: Some *are* worried and concerned.

The challenge for utilities is to acknowledge public awareness and concern about EMF and promote a process of dialogue with customers on the EMF issue. The "process" and the "dialogue" are both critical. Dialogue means talking—back and forth—and listening to customers with sympathy and respect for their feelings as well as their factual understanding. Process emphasizes the ongoing relationship between the utility and its stakeholders, a relationship that is established through the utility's EMF activities and communications.

Only through continuing an open process of dialogue can utilities and their customers understand each other better and work together to achieve mutual agreement on ways to think about and handle the issue of EMF in their communities. ◆

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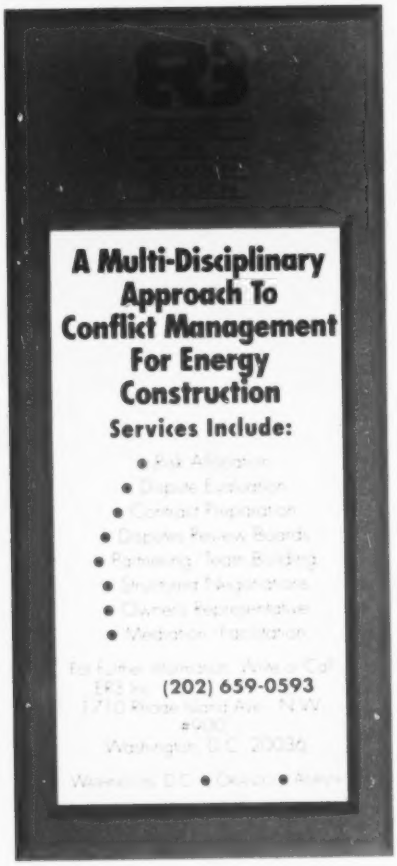

STATISTICAL REVIEW

1992 ELECTRICITY SUPPLY

Net generation by U.S. electric utilities (investor-owned companies, cooperatives, and government utilities) fell 27,581,796 megawatthours (MWh) in 1992. The 1.0 percent drop combined with significant jumps in net imports (up 25.2 percent, or 5,621,595 MWh) and in purchases from industrials (up 18.7 percent, or 25,551,995 MWh) to nudge the electric utility industry's total electricity supply up 3,591,794 MWh, an increase of only 0.1 percent. (See Table 1.)

Utilities' net generation contributed just under 93.6 percent of the total supply, a one point drop from its 1991 share. Purchases from industrials made up 5.4 percent of the total, up from last year's 4.6 percent share, while net imports gained under a fifth of a point.

As a primary energy source, coal's share of net utility generation in 1992 was 56.3 percent, up 1.4 percentage points from its 1991 share. Nuclear accounted for 22.1 percent, and gas accounted for 9.4 percent. Hydro's share dropped to 8.6 from 9.8 percent the previous year. Likewise, oil dropped from 3.9 to 3.2 percent.

Sales to ultimate customers, which were essentially flat due to last year's mild weather, accounted for 91.6 percent of the electricity. Power lost and unaccounted for made up 8.1 percent of the total. The remaining 0.3 percent was accounted for by electric company use, free service, and producer use.

Contributed by the Statistics Department of Edison Electric Institute.

TABLE 1
1992 U.S. ELECTRICITY SUPPLY
Total Electric Utility Industry (megawatthours)

	1992	1991r	% Change
Source			
Net Generation	2,795,963,541	2,823,545,337	(1.0)
Net Imports	27,893,745	22,272,150	25.2
Purchases from Industrials	162,102,212	136,550,217	18.7
Total	2,985,959,498	2,982,367,704	0.1
Utility Fuels			
Coal	1,575,313,496	1,549,730,902	1.7
Oil	88,486,705	111,463,322	(20.6)
Gas	263,689,682	264,131,679	(0.2)
Nuclear	618,805,775	612,565,087	1.0
Hydro	239,470,190	275,517,170	(13.1)
Other	10,197,693	10,137,177	0.6
Total	2,795,963,541	2,823,545,337	(1.0)
Disposition			
Company Use and Free Service	7,088,149	6,787,862	4.4
Lost and Unaccounted for	241,852,872	239,627,529	0.9
Used by Producer	2,515,955	2,710,032	(7.2)
Sales to Ultimate Customers	2,734,502,522	2,733,242,281	0.0
Total	2,985,959,498	2,982,367,704	0.1

Source: Adapted from "Quarterly Statistical Report," March 15, 1993. Published by the Statistics Department of Edison Electric Institute.
r = revised.

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FINANCIAL REVIEW

ASSET-TURNOVER RATIO DECLINES

Although it remains the nation's most capital-intensive industry, the investor-owned electric utility industry's asset-turnover ratio fell for the fourth consecutive year in 1991, dropping to $2.31, its lowest level in the last ten years.

An industry's asset-turnover ratio, a measure of the amount of investment required to earn a dollar of annual revenue (asset base divided by annual revenue), characterizes its capital intensity. By this measure, the investor-owned electric utility industry is 1.2 times more capital intensive than mining, the next most capital-intensive industry, and 2.4 times more capital intensive than the average recorded for all forms of manufacturing. (See Table 1.)

Although the electric utility industry's asset-turnover ratio edged upward for most of the 1980s, since 1987 annual electric operating revenue has grown faster than net electric utility plant, pushing the ratio down. In 1991, revenue grew 5.3 percent, while plant grew only 1.3 percent. The slow growth in net electric utility plant is due, in part, to a decline in construction expenditures and a related increase in depreciation expense. From 1987 to 1991, total construction expenditures declined at an average annual rate of 3.4 percent, falling from $27.0 billion to $23.4 billion.

Steady growth in power purchases from non-utility generators (NUGs) and in demand-side management (DSM) programs over the same period has also depressed the ratio. In general, costs associated with purchased power and DSM are not included in the rate base; consequently, they don't increase a company's asset base. They are, however, included in the company's revenue. In 1991, electric utilities received almost 136,550 gigawatthours of electricity from NUGs. They also spent more than $2.0 billion on DSM programs.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

TABLE 1
CAPITAL ASSETS REQUIRED PER DOLLAR OF REVENUE

Major Industries—1991	Industry Requirement
Investor-Owned Electric Utilities[1]	$2.31
Mining[2]	$1.92
Communications[3]	$0.81
Railroads[4]	$1.74
Investor-Owned Gas Utilities & Pipeline Industry[5]	$1.02
Manufacturing	
Nondurable Manufacturing Industries	
Food & Kindred Products	$0.79
Textile Mill Products	$0.73
Paper & Allied Products	$1.05
Printing & Publishing	$1.08
Chemicals & Allied Products	$1.13
Industrial Chemicals & Synthetics	$1.27
Drugs	$1.15
Petroleum & Coal Products	$1.16
Rubber & Miscellaneous Plastic Products	$0.74
Other Nondurable Manufacturing Products	$0.53
Average of Nondurable Manufacturing Industries	$0.96
Durable Manufacturing Industries	
Stone, Clay, & Glass Products	$1.17
Primary Metal Industries	$0.92
Fabricated Metal Products	$0.74
Machinery Except Electrical	$1.07
Electrical & Electronic Equipment	$0.96
Transportation Equipment	$0.98
Instruments & Related Products	$1.14
Other Durable Manufacturing Products	$0.64
Average of Durable Manufacturing Industries	$0.95
Average of All Manufacturing	$0.96
Retail Trade[2]	$0.52
Wholesale Trade[2]	$0.40

Note: Averages may reflect independent rounding. Some ratios may differ from those previously reported due to reclassifications within specific industries. Data for the investor-owned electric utility industry reflect only net electric utility plant and electric operating revenue; in previous years, some non-electric investment was included.

[1] Net total electric utility assets, average year-end 1990 and 1991, and electric department operating revenues, 1991. *Statistical Yearbook/1991*, Edison Electric Institute, pp.85-86.
[2] Average quarterly assets and total annual sales, 1991. *Quarterly Financial Report of Manufacturing, Mining, and Trade Corporations*, U.S. Bureau of the Census, 1992, first quarter.
[3] Assets, average year-end 1990 and 1991, and operating revenues, 1991. *Moody's Public Utility Manual*, 1992, Vol. 1, p. 2564.
[4] Net investment in plant and equipment, average year-end 1990 and 1991, and operating revenues, 1991. *Railroad Facts*, 1992, Association of American Railroads, pp. 9 &42.
[5] Assets, average year-end 1990 and 1991, and operating revenues, 1991. *Gas Facts*, 1992, American Gas Association, pp.146 & 155. For combination companies, includes only gas operations.

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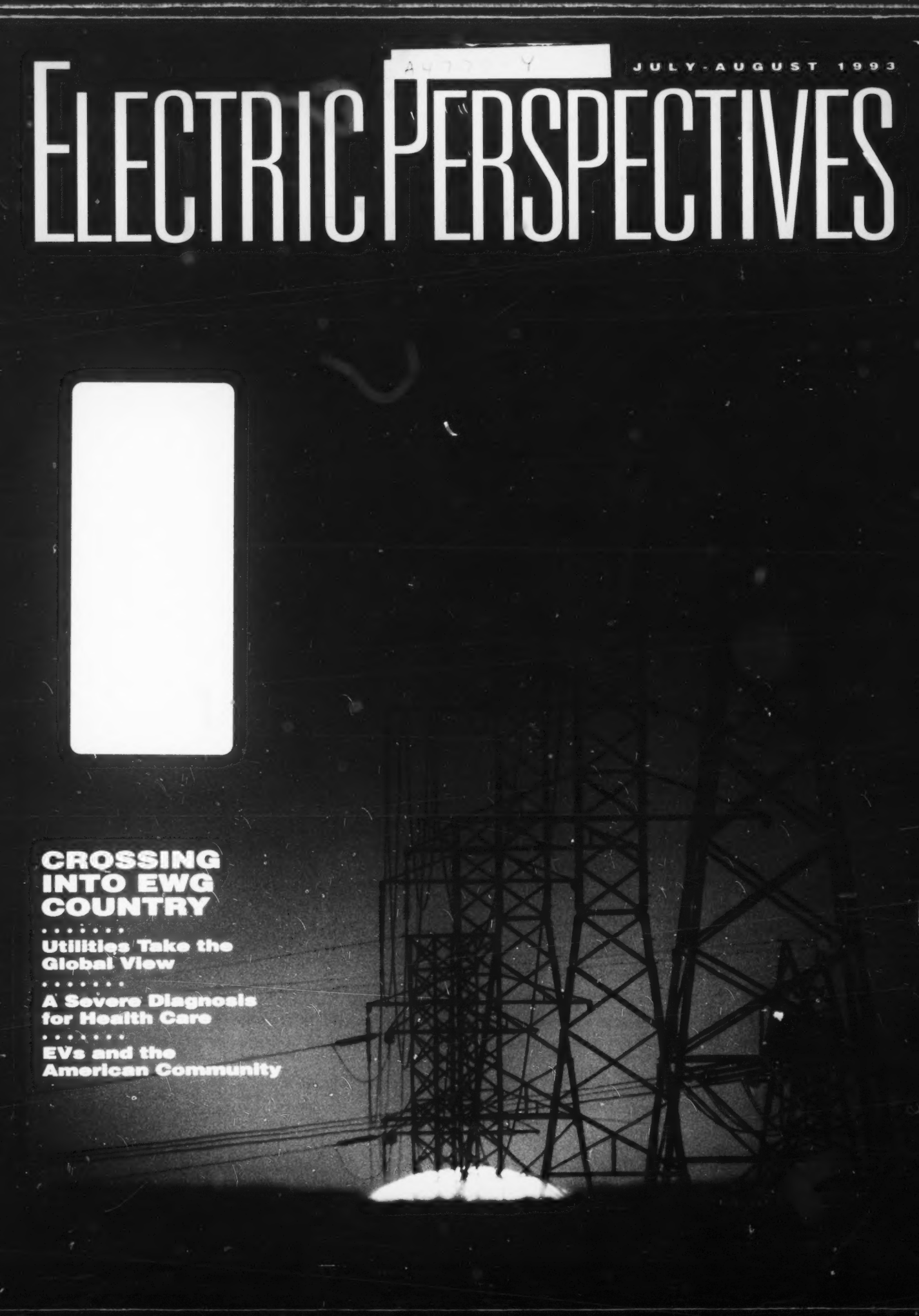
JULY-AUGUST 1993

ELECTRIC PERSPECTIVES



CROSSING INTO EWG COUNTRY

Utilities Take the Global View

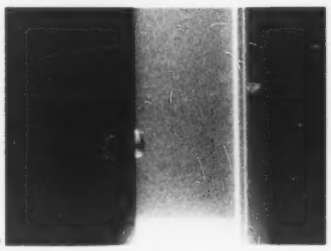
A Severe Diagnosis for Health Care

EVs and the American Community

THE MAGAZINE FOR MANAGEMENT IN AMERICA'S INVESTOR-OWNED ELECTRIC UTILITIES

JULY–AUGUST 1993 / VOLUME 17, NUMBER 4

ELECTRIC PERSPECTIVES



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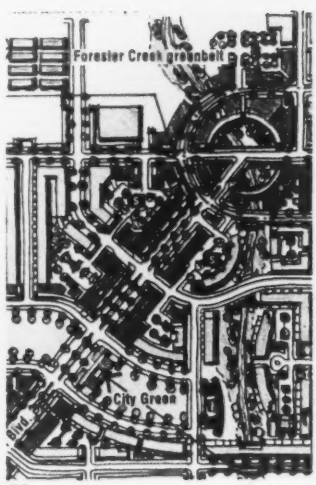

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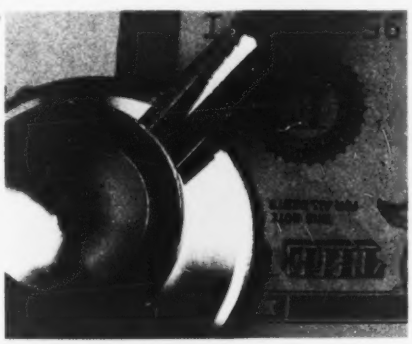

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NEWS & TRENDS

SCARING AWAY THE FISH

For Sonalysts, Inc., in Waterford, CT, the end of the Cold War has an effect on the company's primary business—the design of submarine and surface-ship sonar systems under contract to the Naval Undersea Warfare Center. They're trying to develop commercial products to fill the void.

The Empire State Electric Research Corporation, a research consortium of seven New York utilities, approached them in 1988 to help them out with a perennial problem—keeping fish out of cooling-water intakes at power projects. The Clean Water Act requires that the design of intake structures reflect the best technology available to minimize adverse environmental impact, and utilities have spent millions of dollars improving intake technologies.

Nets and screens can be effective for bigger, firmer fish, but they require extensive maintenance and may not be as effective for safely excluding smaller, softer clupeids—alewives, shad, and herring. A curtain of bubbles in front of the intake has proven to be somewhat of a deterrent. Scaring the fish away with sound is another alternative—in the 1970s, some experiments with piping in loud rock music and setting off a spring-loaded hammer to pound a 55-gallon drum had limited success.

Now, Sonalysts has developed the Electronic Fish Startle System, a prototype acoustical deterrent system that emits a pulsed, high-decibel (158 db), high-frequency sound from the end of an intake pipe. At a recent demonstration at the James A. FitzPatrick nuclear plant on Lake Ontario in New York, the company reports that it cut the number of alewives impinged on the intake trash screen by 87 percent and reduced fish density in front of the intake by 91 percent.

Hydroelectric stations also try to keep fish away from turbine supply pipes, and so a sound system might be useful in scaring migratory fish toward a fish-passage facility, away from the intake. As more than 160 hydroelectric stations are scheduled for relicensing this year, many are under pressure to improve fish protection.

IT GOES WITHOUT SAYING

Hydropower is the grande dame of renewables. And we should say it more often, despite the fact that its age and presence in comparison to other harnessed renewable sources are so great that it hardly needs mention. The first dynamo driven by water turbines went to work in 1880, and today hydro produces more than 10 percent of the electric power in this country. It's cost-efficient, too: The melting snowpack in the Sierra Nevada, for instance, might save up to $32 million in fuel expenses for Southern California Edison; and during one year in the early 1980s, according to Pacific Gas and Electric, hydropower reduced rates by approximately $1 billion. And a hydropower facility produces no emissions.

Major renewable, no emissions—those kind of statements may seem obvious, yet hydro is often taken for granted and often put up against large obstacles. More than 200 projects licensed by the Federal Energy Regulatory Commission (FERC) will be up for relicensing in the next few years; FERC has 157 applications

FINANCIAL REVIEW

1992 EARNINGS UP 8.2 PERCENT

Boosted by a drop in net non-recurring income-reducing items, investor-owned electric utilities' earnings per share before extraordinary items jumped to $1.97 last year. Non-recurring reductions totaled only $1.7 billion in 1992, their lowest level since 1987.

At the same time, unusually mild weather during the first three quarters of 1992 dampened annual revenue growth. Electric operating revenues grew only 1.7 percent despite 2.6 percent growth in the fourth quarter. Total operating expenses increased 2.3 percent, although fuel expenses dropped 3.0 percent due to lower average fuel prices and increases in power purchases.

The equity capitalization ratio increased to 43.3 percent, up from 42.9 percent. Some of the proceeds from a 16.8 percent rise in short-term debt were used to refinance long-term debt at lower interest rates. The long-term debt ratio declined from 50.0 to 49.7 percent.

Tables 1 and 2 are based on unaudited reports submitted by a sample representing all investor-owned electric utilities. Supplemented with Standard & Poor's Compustat Services, data are revised to reflect all company restatements.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

TABLE 1
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY BALANCE SHEET
(Millions of Dollars)

Assets	December 31, 1992	December 31, 1991r	%Change[2]
Utility Plant[1]			
Utility Plant (Including Nuclear Fuel)	$550,862	$531,460	3.7
Less Accumulated Depreciation	182,057	169,251	7.6
Total	$368,805	$362,209	1.8
Construction Work in Progress	24,766	21,399	15.7
Net Utility Plant	$393,571	$383,608	2.6
Investments	$32,140	$29,356	9.5
Current Assets	47,080	45,706	3.0
Deferred Debits	43,277	36,901	17.3
Total Assets	$516,068	$495,570	4.1
Capitalization & Liabilities			
Capitalization			
Common Stock	$101,224	$96,709	4.7
Retained Earnings	54,627	53,080	2.9
Preferred Stock	25,133	24,904	0.9
Long-Term Debt	178,954	174,480	2.6
Total Capitalization	$359,938	$349,173	3.1
Current Liabilities			
Short-Term Debt	$11,847	$10,142	16.8
Long-Term Debt Due Currently	8,759	8,489	3.2
Other Current Liabilities	37,297	36,014	3.6
Total Current Liabilities	$57,903	$54,646	6.0
Deferred Credits			
Capital Lease Obligations, Non–Current Portion	$4,055	$3,590	13.0
Accumulated Deferred Income Taxes	57,283	54,036	6.0
Accumulated Deferred Investment Tax Credits	14,271	14,888	(4.1)
Other Deferred Credits	22,618	19,238	17.6
Total Deferred Credits	$98,228	$91,752	7.1
Total Capitalization & Liabilities	$516,068	$495,570	4.1

Source: EEI Survey Data and Standard and Poor's Compustat Services, Inc.
[1]Includes non-electric utility plant.
[2]Percent changes may reflect independent roundings.
r -Revised to reflect company restatements.

TABLE 2
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY STATEMENT OF INCOME
(Millions of Dollars)

	Three Months Ending December 31,			Twelve Months Ending December 31,		
	1992	1991r	%Change[2]	1992	1991r	%Change[2]
Total Electric Operating Revenues[1]	$39,165	$38,156	2.6	$159,862	$157,164	1.7
Electric Operating Expenses						
Fuel	$7,097	$6,986	1.6	$28,698	$29,587	(3.0)
Purchased Power & Net Interchange	4,562	4,455	2.4	17,332	16,162	7.2
Other Operation & Maintenance	11,516	11,512	N.M.	43,274	42,243	2.4
Depreciation & Amortization	4,422	4,178	5.8	17,345	16,556	4.8
Costs Deferred Under Rate Phase-In Plans	(38)	(145)	(73.9)	27	(311)	N.M.
Taxes Other Than Income Taxes	3,226	3,107	3.8	12,989	12,454	4.3
Income Taxes: Federal & Other	1,183	1,171	1.0	7,441	7,915	(6.0)
Deferred Income Taxes	693	485	42.8	2,594	1,915	35.5
Investment Tax Credits, Net	(139)	(87)	60.0	(427)	(214)	99.3
Total Electric Operating Expenses	$32,523	$31,663	2.7	$129,274	$126,307	2.3
Electric Operating Income	$6,641	$6,492	2.3	$30,589	$30,857	(0.9)
Other Utility Operating Income	560	493	13.7	1,471	1,415	4.0
Total Utility Operating Income	$7,201	$6,985	3.1	$32,060	$32,272	(0.7)
Other Income & Deductions, Net	($503)	($709)	(29.1)	$748	($878)	N.M.
Phase-In Deferrals	46	128	(63.8)	173	434	(60.2)
Allowance for Other Funds Used During Construction	162	150	7.9	605	694	(12.8)
Total Income Before Interest Charges	$6,907	$6,554	5.4	$33,586	$32,522	3.3
Interest Charges						
Interest on Long-Term Debt	$3,553	$3,696	(3.9)	$14,611	$14,979	(2.5)
Other Interest Expenses & Charges	482	534	(9.8)	1,717	1,962	(12.5)
Allowance for Borrowed Funds Used During Construction	(131)	(119)	10.5	(533)	(579)	(8.0)
Net Interest Expenses & Charges	$3,904	$4,111	(5.1)	$15,795	$16,361	(3.5)
Net Income Before Extraordinary Items	$3,004	$2,443	23.0	$17,791	$16,161	10.1
Extraordinary Items	(1)	(337)	(99.8)	(15)	(337)	(95.5)
Cumulative Effect of a Change in Accounting Principle	14	0	N.M.	99	108	(8.2)
Net Income	$3,017	$2,106	43.3	$17,875	$15,932	12.2
Preferred Dividends Declared	461	499	(7.7)	2,009	1,953	2.9
Net Income Available for Common	$2,557	$1,607	59.1	$15,866	$13,979	13.5
Common Dividends Declared	3,655	3,560	2.7	14,592	13,915	4.9
Additions to Retained Earnings	($1,098)	($1,953)	(43.8)	$1,274	$64	1,889.6
Avg. Shares Outstanding (Millions)	8,045	7,836	2.7	7,992	7,800	2.5
Earnings Per Share Before Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle	$0.32	$0.25	28.0	$1.97	$1.82	8.2
Earnings Per Share After Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle	$0.32	$0.21	52.4	$1.99	$1.79	11.2
Common Dividends Per Share	$0.45	$0.45	N.M.	$1.83	$1.78	2.8

Source: EEI Survey Data and Standard and Poor's Compustat Services, Inc.
[1]Revenues are adjusted for intra-industry electricity sales for resale.
[2]Percent changes may reflect roundings.
r-Revised to reflect company restatements.
N.M.-Not Meaningful

REGULATORY REVIEW

1992 RATE INCREASES HIT THREE-YEAR LOW

On an annualized basis, investor-owned electric utilities were granted $2.6 billion in rate increases in 1992, a 51.3 percent drop from the $5.3 billion granted in 1991 and the lowest yearly total approved since 1989. The decrease, which was caused by a drop in the number of cases involving baseload construction projects, follows two years of annual increases.

The percentage of requested rate increases approved by regulators also dropped, falling from 68.7 percent in 1991 to 52.9 percent in 1992.

Many rate increases approved during the first half of 1992 were authorized either for companies that had deferred applying for increases for several years or for companies that are required to make annual rate filings. Increases approved during the second half of the year mainly involved companies seeking rate relief for customary expenses related to operation & maintenance, purchased power, depreciation, and taxes. Nuclear decommissioning costs and expenses related to the Financial Accounting Standards Board's Statement 106 regarding the accrual of post-employment benefits also figured into 1992 rate requests. Several regulatory commissions allowed electric utilities to amortize the costs of implementing FASB 106 for ratemaking purposes, but a number of commissions deferred addressing the issue.

The average return on common equity (ROE) allowed by state commissions in 1992 was only 12.2 percent, the lowest average authorized since 1973. Electric utilities filing for rate increases last year requested, on average, a 12.6 percent return. The comparable numbers for the previous year were 12.5 percent and 13.2 percent, respectively. (From 1990 to 1992 interest rates, as measured by A-rated utility bonds with a 30-year maturity, dropped from 10.01 percent to 8.52 percent.)

TABLE 1
1992 QUARTERLY RATE INCREASES

	Filed During Period		Pending at End of Period		Approved During Period	
	No.	$000	No.	$000	No.	$000
First	9r	408,554r	48r	3,706,072r	17r	381,451r
Second	29r	1,095,721r	58r	3,319,876r	24r	913,017r
Third	12	1,313,388	55	3,852,737	14	313,810
Fourth	19	827,973	53	2,738,325	26	950,486
Year	69	3,645,636	53	2,738,325	81	2,558,764

r = revised

Authorized rate decreases fell to $194.3 million in 1992, down 11.1 percent from $218.5 million in 1991. The average rate decrease granted in 1992 was $12.9 million; in 1991 it was $10.9 million.

Sixty-nine cases requesting rate increases were filed in 1992, down sharply from the 93 recorded the previous year. The decrease reflects the success of the industry's recent cost-cutting measures, including refinancings, which have delayed some of the need for rate increases. Combined, electric companies filed requests for increases last year totaling $3.6 billion, a 38.5 percent decrease from 1991's total of $5.9 billion.

Rate decrease filings for the year totaled $55.1 million, compared to $61.6 million in 1991. Eight requests were filed, three fewer than in 1991.Likewise, the amount of requests for decreases still pending at the year end also declined moderately, from $38.1 million for 1991 to $35.5 million for 1992. The number of such cases pending edged up from four to five.

The dollar amount of rate increases pending at the end of 1992 hit a 20-year low, $2.7 billion. The year before the amount pending at year-end equaled $4.0 billion. The number of cases requesting increases that were pending at year end also fell slightly, 53 vs.56. The relatively small backlog of pending cases also testifies to the success of utilities' cost control efforts—the real price of electricity has declined more than 22.0 percent since 1982.

Table 1 is based on Edison Electric Institute's quarterly rate actions surveys, which are compiled by EEI's rate regulation department. The survey covers rate cases before the Federal Energy Regulatory Commission, state commissions, and municipal bodies involving investor-owned electric utilities. Approved cases are reported in the quarter during which the rate change goes into effect. If regulators order a phased-in increase, the total dollar amount of all phases is reported in the quarter during which the order was issued. Only the final denial of an increase in rates is reported as denied. When a utility is granted a lower increase than it requested, the remainder is not reported as denied; however, when a utility seeks an increase and instead is ordered to decrease its rates, the amount of the increase sought is reported as denied and the amount of the decrease ordered is reported as an approved decrease.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

STATISTICAL REVIEW

WEATHER RESTRAINS 1992 SALES

Electricity sales to ultimate customers by investor-owned electric utilities rose only 4.7 million megawatthours last year, a mere 0.2 percent increase over 1991. Milder-than-usual weather was the chief sales moderator, though its impact was offset somewhat by relatively strong economic growth and relatively low electricity prices.

There were 6.9 percent fewer degree days (heating and cooling) last year than normal and 3.5 percent fewer than in 1991. The fourth quarter proved the exception, however: Heating degree days were up 5.6 percent over the fourth quarter of 1991, boosting the quarter's total sales up 2.1 percent.

As measured by real gross domestic product on an annual basis, the economy grew 2.1 percent last year. The Federal Reserve Board's index of industrial production grew 2.5 percent. Reflecting this economic upswing, sales to commercial customers increased 1.8 percent and sales to industrial customers increased 1.5 percent.

The real price of electricity continued to decline in 1992, as it has since 1982. The average revenue per kilowatthour sold was 7.07 cents, a 0.9 percent increase over the 1991 average but well below the 2.9 percent increase in the consumer price index last year.

Contributed by the Finance and Accounting Division of Edison Electric Institute.

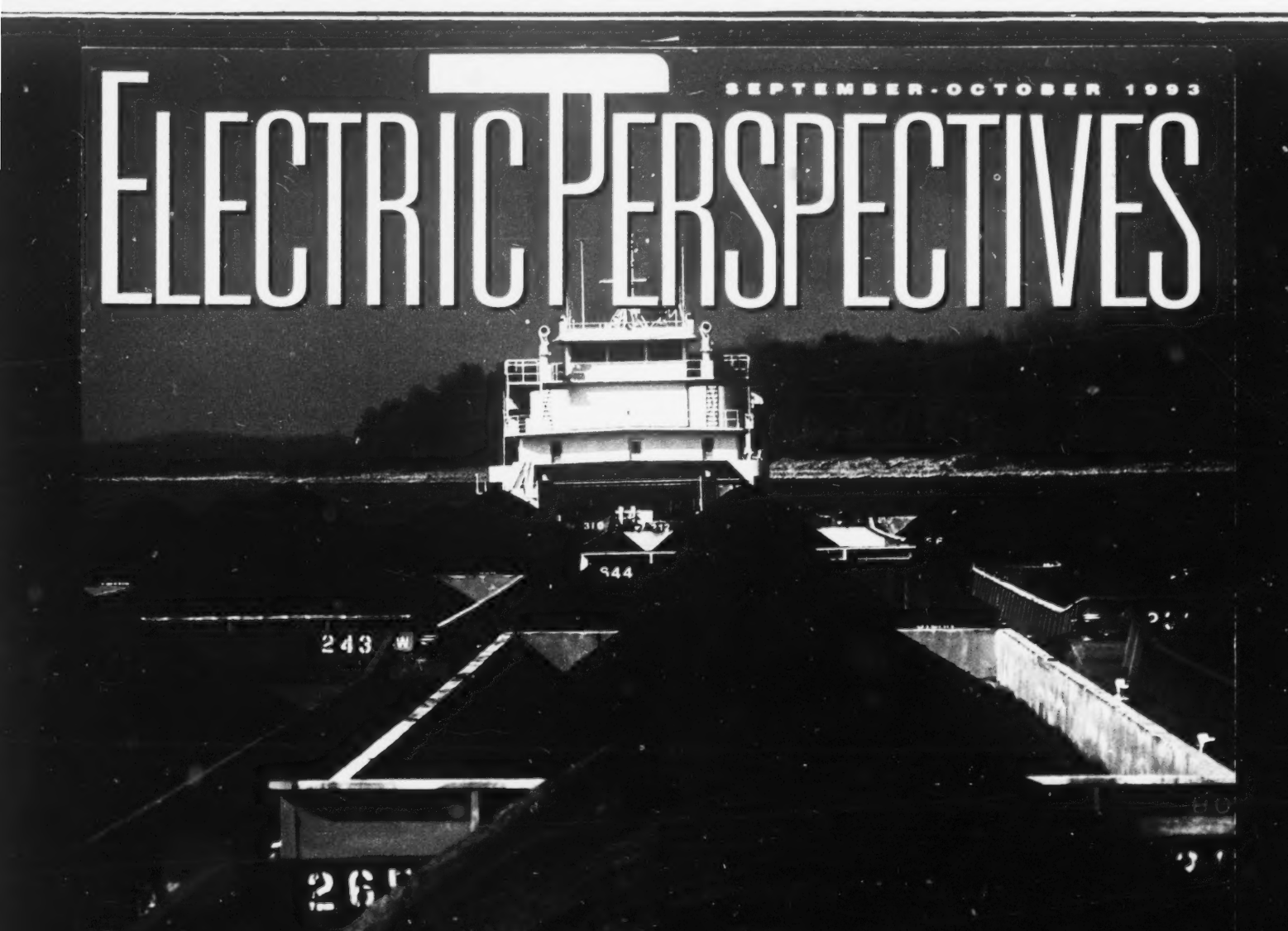
TABLE 1
FOURTH QUARTER CUSTOMER, SALES, AND REVENUE DATA FOR INVESTOR-OWNED ELECTRIC UTILITIES

	Three Months Ending December 31,			Twelve Months Ending December 31,		
	1992	1991	%Change	1992	1991	%Change
Number of Customers						
Residential	75,648,490	74,927,273	1.0	75,347,873	74,620,845	1.0
Commercial	9,481,772	9,392,008	1.0	9,447,929	9,359,924	0.9
Industrial	403,133	396,854	1.6	399,904	395,471	1.1
Street & Highway	145,811	147,703	(1.3)	147,569	145,699	1.3
Other Public Authorities	172,905	170,475	1.4	171,984	169,220	1.6
Railroads	23	23	0.0	23	23	0.0
Interdepartmental	466	470	(0.9)	522	466	12.0
Total Customers	85,852,600	85,034,806	1.0	85,515,804	84,691,648	1.0
Electricity Sales (MWh)						
Residential	165,849,547	161,706,768	2.6	680,406,533	692,512,692	(1.7)
Commercial	153,034,800	150,288,487	1.8	625,645,283	623,214,144	0.4
Industrial	181,852,807	178,991,387	1.6	726,649,369	715,632,815	1.5
Street & Highway	2,819,528	2,828,523	(0.3)	10,595,853	10,505,905	0.9
Other Public Authorities	14,484,195	13,496,329	7.3	58,315,373	54,860,054	6.3
Railroads	613,029	628,488	(2.5)	2,486,159	2,548,909	(2.5)
Interdepartmental	235,960	396,349	(40.5)	1,091,576	1,193,968	(8.6)
Total Sales	518,889,866	508,336,331	2.1	2,105,190,146	2,100,468,487	0.2
Revenues ($000)						
Residential	14,009,335	13,527,961	3.6	58,539,316	58,561,916	0.0
Commercial	11,840,149	11,579,558	2.3	48,904,400	48,127,935	1.6
Industrial	8,985,069	8,867,005	1.3	36,818,415	36,165,260	1.8
Street & Highway	329,581	326,164	1.0	1,311,890	1,284,480	2.1
Other Public Authorities	722,664	693,526	4.2	2,938,398	2,854,073	3.0
Railroads	40,954	43,492	(5.8)	173,608	177,900	(2.4)
Interdepartmental	8,787	7,416	18.5	73,067	77,081	(5.2)
Total Revenues	35,936,539	35,045,121	2.5	148,759,095	147,248,646	1.0

Source: Edison Electric Institute, Statistics Department

SEPTEMBER-OCTOBER 1993

ELECTRIC PERSPECTIVES



APPRAISING DIVERSIFICATION

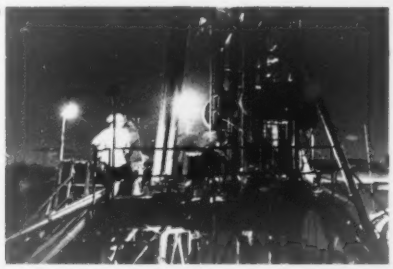
The Devil in Order 636's Details

Decommissioning Costs

Payers and Health-Care Reform

THE MAGAZINE FOR MANAGEMENT IN AMERICA'S INVESTOR-OWNED ELECTRIC UTILITIES SEPTEMBER-OCTOBER 1993 VOLUME 17, NUMBER 5

ELECTRIC PERSPECTIVES



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DIVERSIFICATION REDUX 10

Diversification got a bad rep in the last decade. But if you look at the results of utility ventures in general, you'll find that they're doing a better job for shareholders than you thought.

BY [illegible]

ORDER 636: A REVOLUTION OF DETAILS 28

Full-scale application of Order 636 begins in November on natural gas pipelines across the country. Will its sweeping nature and good intentions overcome the problems it could create? What issues do electricity generators face?

BY [illegible]

THE COST OF SHUTTING DOWN 42

As we enter a new phase of nuclear power, what are we to do with unexpected decommissioning costs, escalating fees for waste disposal, regulatory uncertainty, and multimillion-dollar obligations? First of all, don't panic—the estimates aren't as bad as they seem.

BY [illegible]

CUTTING THE PRICE OF HEALTH CARE 56

Two factors may force passage of national health-care reform in Congress—cost and state-level legislation. Electric utilities must promote both comprehensive reform and a proposal that reflects the payer's perspective.

BY [illegible]

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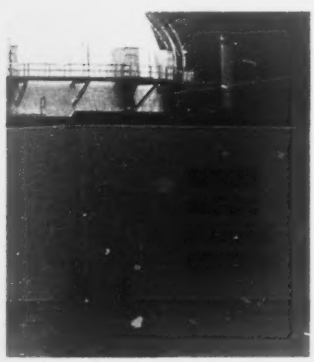

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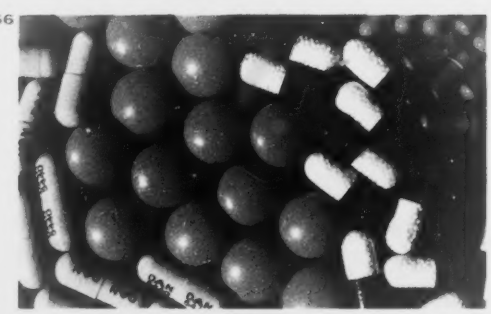

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On the cover: Water transportation—one of DCI Group's core subsidiary's diversified activities. Photo by Robert S. Woodcock for Tampa Electric Company.

ELECTRIC PERSPECTIVES

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NEWS & TRENDS

REACHING COMMON GOALS

Five investor-owned electric utilities learned in July that they were winners of Edison Electric Institute's Common Goals Award. Presented every year since 1987, the award goes to companies with programs judged to be the finest examples of cooperative endeavor. The prizes are in five areas:

- *Community Responsibility/Special Needs.* Central Maine Power Company is the first private company in the nation to win a federal grant to help people with disabilities find employment in the community. Having won the grant, CMP is now working toward placing more than 1,200 workers in productive, supported-employment positions.
- *Customer Satisfaction.* Acting on an employee's suggestion, Georgia Power Company has been guaranteeing its services to electric-power customers since 1991. Such guarantees (backed up by financial restitution) include making new service connections by a promised date, repairing outdoor lighting, respecting customers' property, and providing courteous service.
- *Educational Partnerships.* Entergy serves a region with high levels of poverty, and the Entergy 2000 program is designed to foster economic development by fostering education. Entergy reports that one of its programs has helped more than 5,000 adults learn to read.
- *Energy Management.* Since 1990, Long Island Lighting has helped not-for-profit organizations—religious, health-care, and charitable groups among them—with energy-management problems. The utility provides free energy analysis and help in acquiring approvals for upgrades and rebates. In 1992, 296 organizations received $885,000 in rebates.
- *Environmental Partnerships.* In 1991, Carolina Power & Light Company became the first private U.S. company to sponsor an entire park system. In 1992, it expanded beyond North Carolina (where it has committed $144,000 over a four-year period) into South Carolina, where it now sponsors seven parks and provides $44,000 in funding. The program includes sponsorship of environmental education and volunteer efforts.

On another award note, it is impossible to neglect mention of Arizona Public Service's attainment of the Edison Award, which was presented at EEI's annual convention in Charlotte, NC, last June. The utility's 1992 accomplishments are impressive. Among other things,

- it cut the cost of electricity production by 10 percent;
- employees cut the $615 million operating, maintenance, and fuel budgets by more than 7 percent;
- it compiled the highest safety and customer satisfaction records in its history;
- its 7,000 employees volunteered more than 50,000 hours to civic organizations; and
- it earned $214 million in 1992—versus a loss of $256.1 million in 1991.

OPEN FOR BUSINESS

Uranium enrichment is a critical step in the process of manufacturing nuclear fuel for commercial reactors. Since the 1940s, the U.S. government, through the Department of Energy, had handled the process exclusively at its gaseous diffusion plants in Paducah, KY, and Pikestown, OH, and

updates on its emergency response efforts after the hurricane and for that also received the Public Relations Society of America's Best of Silver Anvil award (out of 45 Silver Anvil winners) for crisis communications.

In the first month following the storm, staffers responded to more than 1,600 media calls and conducted daily news briefings. To deliver safety messages to the public, the communications staff used advertising on 54 radio stations, 8 TV stations, and 7 major newspapers. Employees received information via daily updates, a daily live television program, and special issues of FPL publications.

In addition, the company's investor relations staff set up a teleconference with FPL's CEO and 75 industry analysts and portfolio managers.

The results? According to FPL, the employees stayed focused and committed, there were no customer electrical injuries and fewer than six injuries among the more than 4,000 field-crew members, and stock prices remained stable. In fact, post-hurricane surveys show that customer satisfaction with the company has actually increased by 20 percent.

DONATIONS, PLEASE

Got any allowance you want to give up for a good cause? Northeast Utilities is donating 10,000 SO$_2$ allowances to the American Lung Association for permanent retirement. The allowances, worth an estimated $3 million, are to go into a national repository established by NU and the ALA. Of course, the repository will accept other utility donations.

With the gift, the ALA intends to sell symbolic pollution-retirement certificates to raise money.

The allowances represent 7 percent of NU's surplus allowances between 2000 and 2005. The donation hinges on state regulatory approval.

Working Assets Long Distance, a phone company, has developed another way to take the allowances off the market. The company is encouraging its customers to round up their phone-bill totals and promises to buy and retire allowances with the extra money.

UTILITY CONSTRUCTION

According to estimates from Edison Electric Institute, construction expenditures for electric utility plant (including the allowance for funds used during construction) increased to $25.5 billion in 1992 from $23.4 billion for 1991, the first annual increase in AFUDC-included construction expenditures since 1989. Between 1993 and 1995, investor-owned electric utilities project $84.1 billion's worth in construction expenditures, an average of $28.0 billion a year.

The increase in electric generating plant construction expenditures will be due primarily to increased expenditures for combustion turbines. Transmission and distribution facility construction will account for 46.6 percent of total electric utility expenditures by 1995. In 1992, however, distribution facility expenditures showed a decrease, correlated as they are to the completion of new housing units. Due to 1991's recession, home completions decreased, but the current economic recovery should boost housing.

Even so, utility plant construction expenditures were $1.8 billion less than last year's forecasted 1992 amount. Several companies reported that incremental generation additions were less expensive than originally estimated, due in part to lower financing rates, cost-cutting measures, reduction of generating needs brought about by mergers, and success of conservation programs.

INVESTOR-OWNED ELECTRIC UTILITY ESTIMATED CONSTRUCTION EXPENDITURES
(Millions of Dollars)

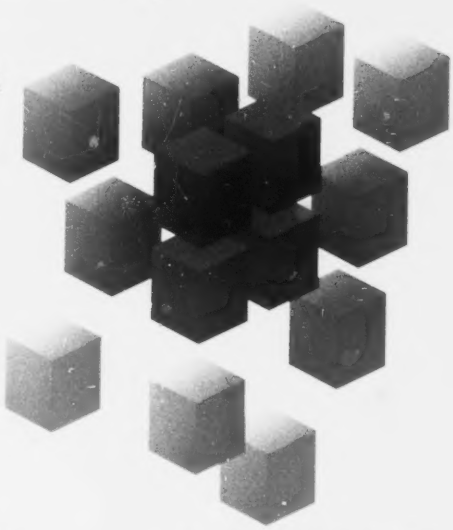
	1991u	1992p	1993	1993-1995
Electric Generating Plant				
Nuclear	$3,206	$3,143	$2,533	$7,039
Coal	4,084	3,375	4,877	14,356
All Other	1,032	2,764	3,215	10,674
Total	$8,322	$9,282	$10,626	$32,069
Transmission & Distribution Facilities				
Transmission	$2,293	$3,457	$3,422	$10,656
Distribution	8,781	8,615	9,168	28,520
Total	$11,073	$12,071	$12,590	$39,176
Miscellaneous Plant	2,437	2,521	2,596	7,584
Nuclear Fuel	1,537	1,596	1,599	5,253
Total Electric Utility Plant	$23,370	$25,470	$27,411	$84,081
AFUDC in total	$1,121	$1,348	$2,282	$5,368
Clean Air Act compliance expenditures in total	N/A	$1,041	$2,095	$5,451

u-EEI Statistical Yearbook/1990.
p-preliminary data.
Note: Not included are expenditures by combination companies for gas plant and other nonelectric utility plant.
Source: EEI Finance and Accounting Division.

Gulfcoast Transit runs ocean-going tug-barges that transport dry bulk goods, including coal. It's a subsidiary of TECO Transport & Trade Corporation and a diversification venture by TECO Energy, TECO Transport's and Tampa Electric's parent company.

DIVERSIFICATION REDUX

Diversification got a bad rep in the last decade. But if you look at the results of utility ventures in general, you'll find that they're doing a better job for shareholders than you thought.



BY JEAN REAVES ROLLINS

Diversification among investor-owned electric utilities has had a checkered past, with some highly visible, notably unsuccessful efforts. Now, the term often engenders fear and trepidation in the minds of utility management, regulators, shareholders, and customers. For some, diversification is a long-hand way to get to a four-letter word.

That's an unfortunate perception—and misguided. The U.S. electric utility industry faces numerous business challenges, many of which portend fundamental changes in the nature of the business. The utility executive finds himself managing a core business where revenue growth prospects are hazy, units sales relatively flat, cost structures increasing, and generation capacity aging—and all the while functioning in a heavily regulated environment. The most recent set of changes arises from the Energy Policy Act of 1992, legislation that promises to alter the industry's structure and the way electricity is provided. Specifically, the executive's challenges include:

- deregulation;
- federal regulation, including environmental;
- state and local regulations concerning demand-side management and the methods by which companies will be made whole for the successful implementation of such programs.

Jean Rollins is vice president of utility practice with The COFAX Group.

- heated competition from independent power producers, cogeneration, gas, and other electric utilities; and
- sluggish base business growth.

Were this the scenario in another industry sector, the obvious remedy would be diversification into other businesses—vertical, horizontal, or out-of-industry. Given the short- to medium-term prospects for the average electric utility's base business, careful diversification may very well provide a hedge against the less attractive trends in the core business. Instead of dismissing diversification out of hand, we should consider the valuable lessons from the successes and mistakes of others, lessons that, appropriately applied, can help steer a successful diversification program.

A Look at Trends

The past 30 years have seen three distinct phases of electric-utility diversification. The first, beginning in the late 1950s and running through the early 1970s, was a period of vertical integration, with utilities diversifying backward into the mining and distribution of various fuels for their generating units.

The second distinct trend—the one uppermost in the public perception—began in the late 1970s and continued through the late 1980s. Here utilities engaged in the same conglomerate approach to diversification as most other industries. Founded on the theory of not putting all your eggs in one basket, this was a period of creating a portfolio of businesses to hedge against business-cycle and other risks, and one of heavy reliance on out-of-industry mergers and acquisitions. Forays out of a utility's core business and into banking, insurance, telecommunications, real estate, factoring, and leasing businesses were the order of the day. While in some cases the portfolio approach had some success, the

In the last decade, utility forays into real estate have received mixed reviews. Today, most new ventures stay closer to the core business.

TABLE 1

DIVERSIFICATION'S ROLE: A SAMPLE

Company	% Diversified Assets 1992	1990
Hawaii Electric	63.7	62.9
MDU Resources	45.1	45.0
PacifiCorp	38.0	38.3
Iowa-Illinois Gas & Electric	32.0	22.2
Potomac Electric Power	30.0	26.5
TECO Energy	30.0	24.4
Minnesota Power	29.4	27.0
CMS Energy	29.0	30.2
Black Hills Corporation	28.0	29.9
UtiliCorp	26.9	20.7
Montana Power	25.7	23.0
Florida Progress	25.4	30.3
Baltimore Gas & Electric	18.0	15.5
SCECorp	17.8	10.8
Houston Industries	17.7	13.9
Public Service Enterprise	17.0	17.1
Midwest Resources	12.0	5.4
CILCORP	11.0	19.7
LG&E Energy	11.0	0.0
Portland General	11.0	11.5
Dominion Resources	9.9	7.5
FPL Group	9.6	25.5
WPL Holdings	9.3	3.4
Oklahoma Gas & Electric	8.9	8.2
San Diego Gas & Electric	7.2	4.6
Washington Water Power	7.1	9.3
IPALCO Enterprises	6.8	4.8
Orange & Rockland Utilities	6.5	5.7
Central Vermont Public Service	5.2	5.6
Atlantic Energy	5.0	5.2
Delmarva Power & Light	5.0	6.4
Tucson Electric	4.0	10.2
Duke Power	3.8	1.9
Pacific Gas & Electric	3.6	1.9
Southwestern Public Service	3.2	2.74

overwhelming majority of the time it failed.

The latest phase of diversification is a direct reaction to the widespread failure of unrelated diversification. Utilities, and industry in general, have divested unrelated investments, replacing them with more core-related businesses that are generally smaller in magnitude and are often start-up ventures with limited capital exposure. Typical of these activities are engineering services, consulting with others on plant construction and operation/maintenance, independent power production, and cogeneration technologies. The jury is still out on the wisdom of many of these ventures—most have yet to reach maturity—but failures are unlikely to have the same devastating effects on the parent company as in the past. The financial exposure is significantly lower.

Another emerging trend is a heightened interest in international opportunities. UtiliCorp, SCECorp, Southern Company, and Houston Industries (to name just a few) all have invested in promising ventures outside the United States, primarily in power production and electricity distribution.

Seeing the Forest Instead of the Trees

In 1991, The COBA Group completed a wide-ranging study of the electric utility diversification experience. (An update is currently underway.) At the time, many clients had begun to pose hard questions concerning the wisdom of utility diversification, and although there were a few reports on the subject, none were detailed or timely enough to offer comprehensive answers. COBA examined 99 utilities for the study—62 that had measurable diversified ventures and 37 that were not diversified.

The results were surprising. For one thing, the types of businesses used for diversification are more varied than one would imagine. (See Figure 1.) Ventures ranged from independent power projects to telecommunications to whole or partial investment in demand-side management companies. Despite this range, there remains a commonality among the ventures, namely the dominance of indepen-

FIGURE 1

VENTURES BY BUSINESS TYPE

FIGURE 2

DIVERSIFICATION BY AGE

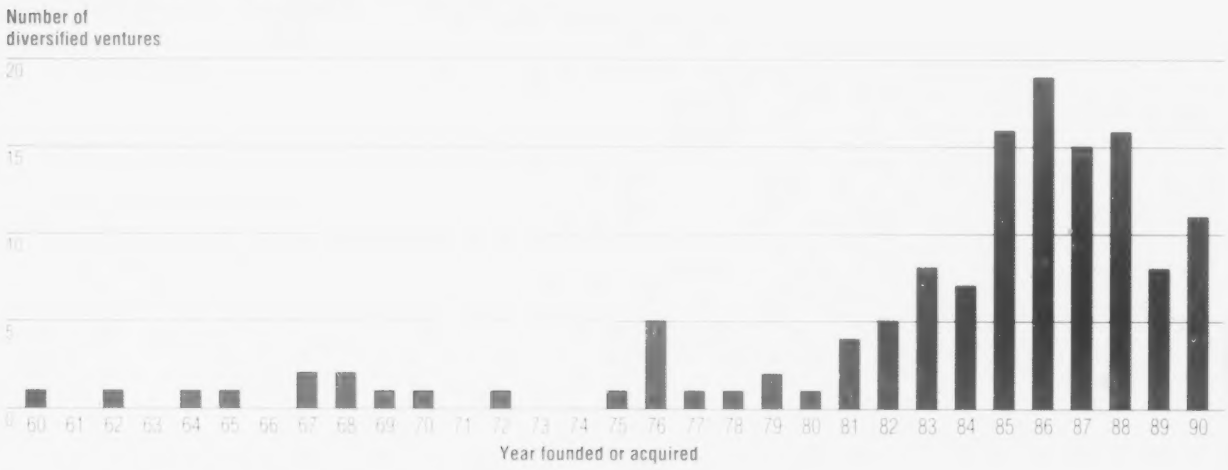
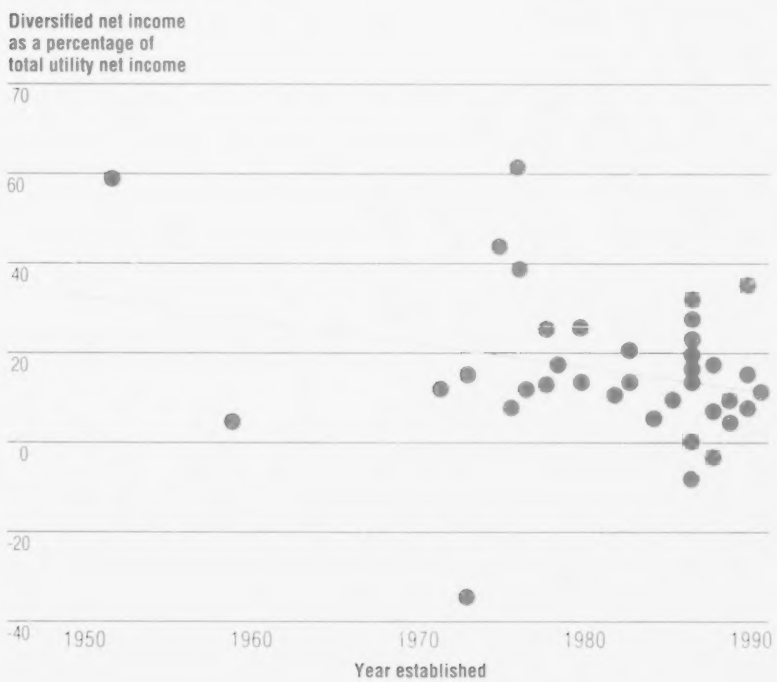


FIGURE 3

DIVERSIFICATION'S CONTRIBUTION TO INCOME



Note: Figure excludes four companies that took write-offs in real estate, banking, and insurance.

dent power, cogeneration, and real-estate investments.

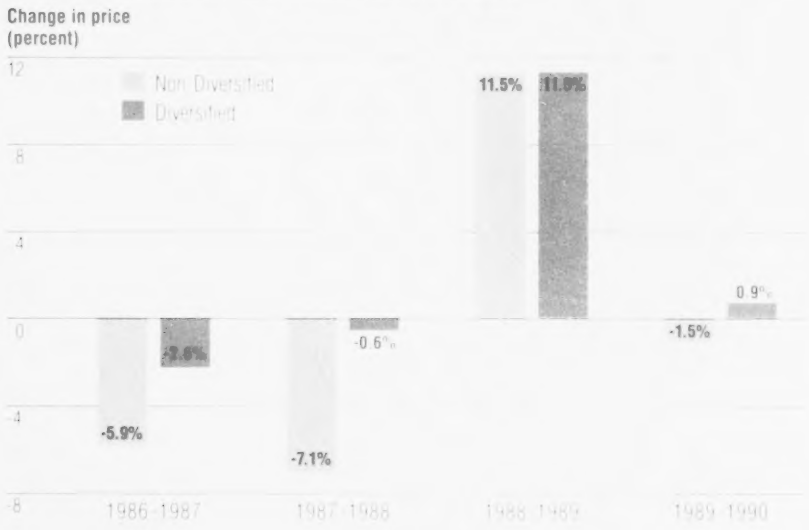
Since these analyses were completed, several companies have taken substantial asset write-offs. But several have also increased the size of their diversified holdings. (Table 1 ranks 35 companies by the percentage of their diversified assets to their total assets in1990 and 1992.) In fact, despite the publicity surrounding some diversification mishaps in the late 1980s, one of the study's major findings is that diversification in the industry is not dying but growing modestly.

Indeed, to a great degree, we are still at the emergence of utility diversification. The median age of extra-utility ventures is less than seven years old, and only 15 percent or so of these businesses are more than 10 years old. (See Figure 2.) That's important to remember when we feel nervous about diversification: In spite of the well-known problems faced by three or four utilities in their diversification efforts in the 1980s, we should understand that most programs have yet to reach investment and cash-flow maturity.

A simple fit correlation analysis (Figure 3) supports this premise. You can see a relationship between the contri-

FIGURE 4

COMMON STOCK PERFORMANCE, 1986-90

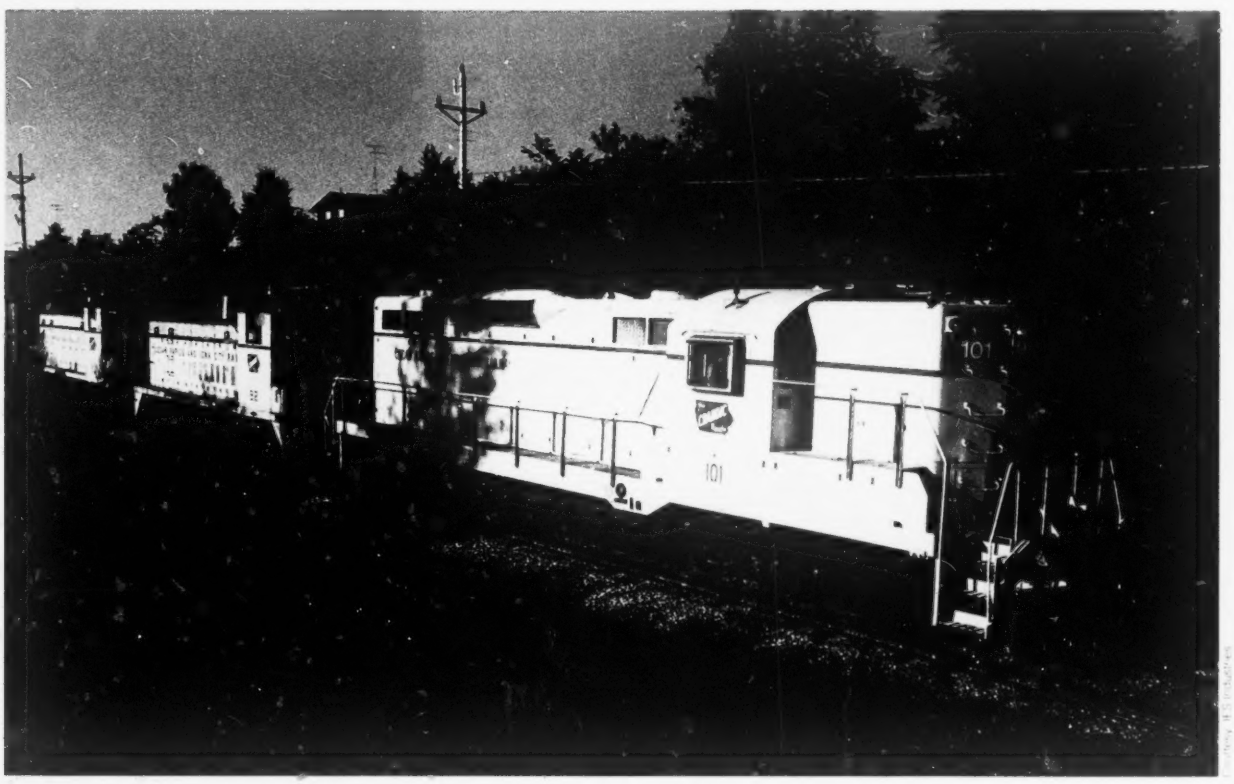


Note: Figure excludes four companies that took write-offs in the years studied. Energy companies.

bution to net income and the age of the venture: The older the diversified venture, the larger its contribution to net income. This is due in part to proactive management's weeding out the bad ventures in a timely fashion, to the evaluation and either reinforcement or divestment of marginal ventures, and to successful ventures achieving cash-flow maturity. All of those take time.

One of the most impressive findings also runs against popular perception. The relative youth of most ventures notwithstanding, diversified companies have generally outperformed nondiversified companies on such key measures as return on equity, earnings per share, common stock price, and yield and price to earnings ratios. (See Figure 4.)

Iowa Electric Light and Power's parent, IES Industries, runs the Cedar Rapids and Iowa City (CRANDIC) Railway—a short-line freight carrier serving industrial customers.



Learning from Missteps

Admittedly, there have been a handful of notable exceptions to the general trend. A few utilities have run into huge problems with ventures into such businesses as life insurance, real estate, banking, and savings and loans. Several others have taken write-offs during the past few years, divesting themselves of under-performing acquisitions, which were mostly failed ventures in IPPs, real estate, and mining operations.

For utilities embarking on diversification and those with existing programs, these unsuccessful ventures illustrate several key lessons—and it would be wise to heed them.

Most of the larger failures were due to unsound acquisitions. The ventures were in fields highly unrelated to the utility's core business, which meant that in many cases the utility brought only cash and little management expertise to the table. Also, because it knew too little about the business or industry it was entering, the utility

By James T. Beale, Jr.

For the utilities that seek to diversify, the key ingredients are the same as any kind of investment: economic viability, proven technology, available operating expertise, a stable political and regulatory climate, experienced and creditworthy sponsors, and mutually interdependent economic interests.

International diversification is no different, but it is clear that utilities must bring a great deal of intelligence, scrutiny, and diligence to such projects.

Looks Great!

So many businesses seem ripe for utility diversification, but nothing may be as tempting as some of the international markets. No one questions the enormous and growing need for electricity in the South American market, for example. Nor does anyone question that the economic and political climates in Latin America have become more investor-friendly: The $9.2 billion in Latin American Eurobonds issued last year, up from nearly nothing four years ago, is ample evidence of the change.

Still, realizing these opportunities can be very complex. Risk varies depending on the country and on such factors as the regulatory climate, sovereign credit history, laws regarding repatriation of profits and benefits, and political stability. Indeed, we will never see the capital availability of the 1970s in these markets again. While commercial banks are slowly returning to Latin America after their traumatic experiences in the 1980s, they are doing so only in the company of binational export credit agencies, multilateral agencies, insurance companies, and the public markets, and on very different terms—the appetite for sovereign risk is next to nil. Rather, the current preference is for minimum-risk investment, particularly for project finance investment.

Mitigating the Risk

Project financing, or contract lending, is contractually supported cash-flow financing where contracts limit volatility in cash flows based on a thorough risk analysis and quantification.

In project financing, a single-purpose project company is established to develop the project. Whatever its legal structure—joint venture, corporation, partnership—the company begins with no creditworthiness, no existing business, no balance sheet, and no revenue stream or cash flow. It has only sponsors or parent companies, and a limited commitment of equity, usually 20 percent or less of the cost of the project.

In effect, this financing mechanism creates creditworthiness and assigns risk to contracting parties with credit substance. The combination of contracts stabilizes and secures the cash flow and creates the creditworthiness, while limited-recourse lending insures that creditors have access to the assets, contracts, and cash flow of the project only—and not to the cash flow of the parent companies. For utilities that view international diversification in independent power projects as iffy, project financing offers a buffer to the project's business risk.

Due Diligence

But that takes work. The basic premise of contract lending is to avoid risks altogether, rather than manage them. This is accomplished through exhaustive risk analysis and due diligence. Risk analysis will typically include construction risk, operating risk, supplies and raw materials risk, infrastructure risk, currency risk, political and regulatory risk, and the risk of force majeure. The contracts based on the analysis are, after all, the lifeblood of the project and must be financeable and enforceable.

The complexity is lessened by taking on local legal, commercial, and financial partners. These partners provide a critical understanding of law, permitting issues, and cultural conventions, and they ensure local commitment to the success of the project. For U.S. utilities, local participation is best secured through a joint-venture project company structure.

Another critical component in international project financing is the multilateral financing agencies and binational export credit agencies (ECAs). In addition to the traditional role they play as a guarantor of loans, ECAs bring two major benefits to any project in which they participate: a willingness to lend for up to 15 years (most commercial banks prefer shorter tenors of up to eight years) and indispensable political clout.

Any survey of Latin American project companies reveals that U.S. utilities are the preferred partners in project financings because they provide expertise and experience. And utilities are interested because power generation is a field they know and one that allows them to diversify their asset base and income stream.

And the reward for diversification? After-tax returns on equity can be as high as 20 to 30 percent. For U.S. utilities that have watched their unregulated domestic ROEs slide to 15 percent and below, those are promising numbers indeed—and perhaps worth the diligence and analysis that any such venture demands.

James T. Beale, Jr., is a managing director in charge of the public utilities division of The Chase Manhattan Bank, N.A.

TABLE 2.

SOME TOP-PERFORMING ELECTRIC COMPANIES

Company	1992 Three-Year Average ROE	% of Diversified Assets	Diversified Activities
Black Hills Corporation	16.2%	[illegible]	[illegible]
Dominion Resources	12.1%	[illegible]	[illegible]
MDU Resources	11.6%	[illegible]	[illegible]
Minnesota Power	15.3%	[illegible]	[illegible]
Montana Power	11.1%	[illegible]	[illegible]
TECO Energy	15.1%	[illegible]	[illegible]

might have performed inadequate commercial due diligence. The fact that the diversified ventures were large in scale in relation to the size of the parent utility, limiting the utility's ability to adapt to market downturns, compounded the impact of that insufficient analysis.

Also, the utility often miscalculated the competitive forces affecting the acquired businesses, a problem that was intensified by poor monitoring of its investments. Several of the smaller failures, for example, were in independent power production and alternative-energy companies. The utility underestimated how critical firm power sales and fuel-sourcing contracts were to the project's viability.

With few exceptions, expectations of synergies went unfulfilled. Management frequently did not thoroughly and realistically evaluate potential economies of scope, and payback expectations and timeframes were often unrealistic.

Learning from Successes

Given the sheer dollar value of some of the recent wayward ventures, it is easy to see why failed diversification efforts have overshadowed the numerous successful programs. But to a large degree, it is a question of perception. In actuality, some of the top-performing investor-owned electric utilities over the past three years have been those with diversified holdings. (See Table 2.)

Just as there are factors common among unsuccessful ventures, the utility executive can take a number of lessons from the shared management characteristics found in the less heralded success stories.

For the most part, these utilities had strong management teams and were financially healthy before undertaking the diversification program. They were aggressive early entrants in growth markets and, avoiding the tendency to

PacifiCorp (operating through Inner PacifiCorp) owns Pacific Telecom, a top-ten non-Bell phone company serving western states.

throw good money after bad, were quick to exit inadequately performing ventures.

They diversified via small start-ups or through acquisition of highly core-related businesses, such as consulting services to industrial sectors supporting energy-related fields. They undertook joint ventures only with partners that had experience in the new business operations.

Several companies are still actively pursuing diversification that is unrelated to their core business, but the dominant trend today is definitely toward more core-related activities—that's where a utility's experience is, that's where its management expertise is. For an electric utility seeking to diversify its company's holdings, redoubling efforts on investing in businesses that are closely related to its core strengths means

- a careful and honest appraisal of the company's true strengths, weaknesses, and capabilities;
- an in-depth assessment of diversification's role vis-a-vis the core business, considering the financial aspects (reasonable expected returns, appropriate debt levels, etc.), human resources issues (skill maintenance, development, and training transfer among business units), and synergies or a future value imparted to the core business for taking on the venture;
- balancing projects across a development spectrum (that is, considering local versus international, building versus acquisition, and so on);
- thorough due diligence (that is, in-depth business-level strategy research, not just an examination of accounting records) of investment opportunities, acquisitions, and joint ventures (see the sidebar, "International Diversification and Project Finance"); and
- a careful match of skills and capabilities with venture partners and others needed to excel in the new market.

Stick to a Flexible Game Plan

Most executives from companies with successful diversification programs strongly stress the importance of hav-

At Wyodak, the Powder River Basin's oldest coal mine, an electric shovel digs out backfill for Black Hills Corporation's Wyodak Resources Development.

THE ATTRACTIVENESS AND FIT OF A VENTURE

ATTRACTIVENESS		FIT
Financial	Strategic	
Materiality	Market size	Market knowledge
Time to payback	Market growth	Capabilities
Return on capital	Competitors	Synergies
Impact on capital structure	Access to customers	Access to capital
Contingent liabilities	Management depth	Management availability
	Barriers	Regulatory restrictions

ing a clearly defined strategy, determined and consistent execution, and continuous reappraisal and redirection in light of feedback on the new experiences. Here's one approach for designing and executing a successful program:

- *Carefully define areas of interest.* Keep the focus narrow, on your business strengths—exceptions to agreed areas of interest must be well justified.
- *Define attractiveness and fit criteria.*

TECO Coalbed Methane, in Alabama, produces gas from coalbeds around Tuscaloosa. The wells represent significant tax credits.

(See Table 3.) Assign each a weighting factor, state your strategy clearly, understand your competencies, and clearly spell out measurable objectives.

- *Assess and establish priorities.* Avoid a shotgun approach to implementing the program, manage the program proactively, and change before you are forced to change.
- *Examine entry routes carefully.* Consider all methods (acquisition, entrepreneurial or internal start up, joint ventures, etc.), compile a comprehensive list of potential targets, and define the management talent needed.
- *Reassess priorities in light of your entry options.* Perform rigorous due diligence on selected targets and carefully plan joint ventures with respect to each company's skill base, goals, and culture.

This exercise is critical in weeding out ventures that initially appear to offer synergies with the core business, but upon further investigation lack a financial, strategic, or general corporate fit. For this decision analysis framework to work, however, you must maintain throughout the process complete objectivity with respect to the true strengths and limitations of your current organization and business. Synergy, as a concept, has often been used (and overused) to justify fairly blatant business mismatches—the vagueness and hope embodied in the word can give you a false reading on a situation. Having a culture and management team that are open to frank discussion can help you avoid very costly diversification miscues.

Not a Bad Picture

In all, COBA's analysis of the diversification experience in the U.S. electric utility industry has revealed that investing in businesses outside the core electric activities ushers in new and different risks. This riskiness, when skillfully managed and mitigated, can indeed equal additional returns for the utility. The trick, however, lies in having the management skill and internal processes in place to select avenues for diversification carefully that "fit" the company's competitive strengths.

Like most other industries in the United States, utilities are swept up in a back-to-basics movement, divesting unrelated business units in favor of those nearer their spheres of expertise. Amid all of the resulting ambiguity, one message is clear: The top performing utilities of the 1990s will likely be those that look for innovative ways to improve their core businesses. Diversification into related fields can be one such key to higher performance. ◆

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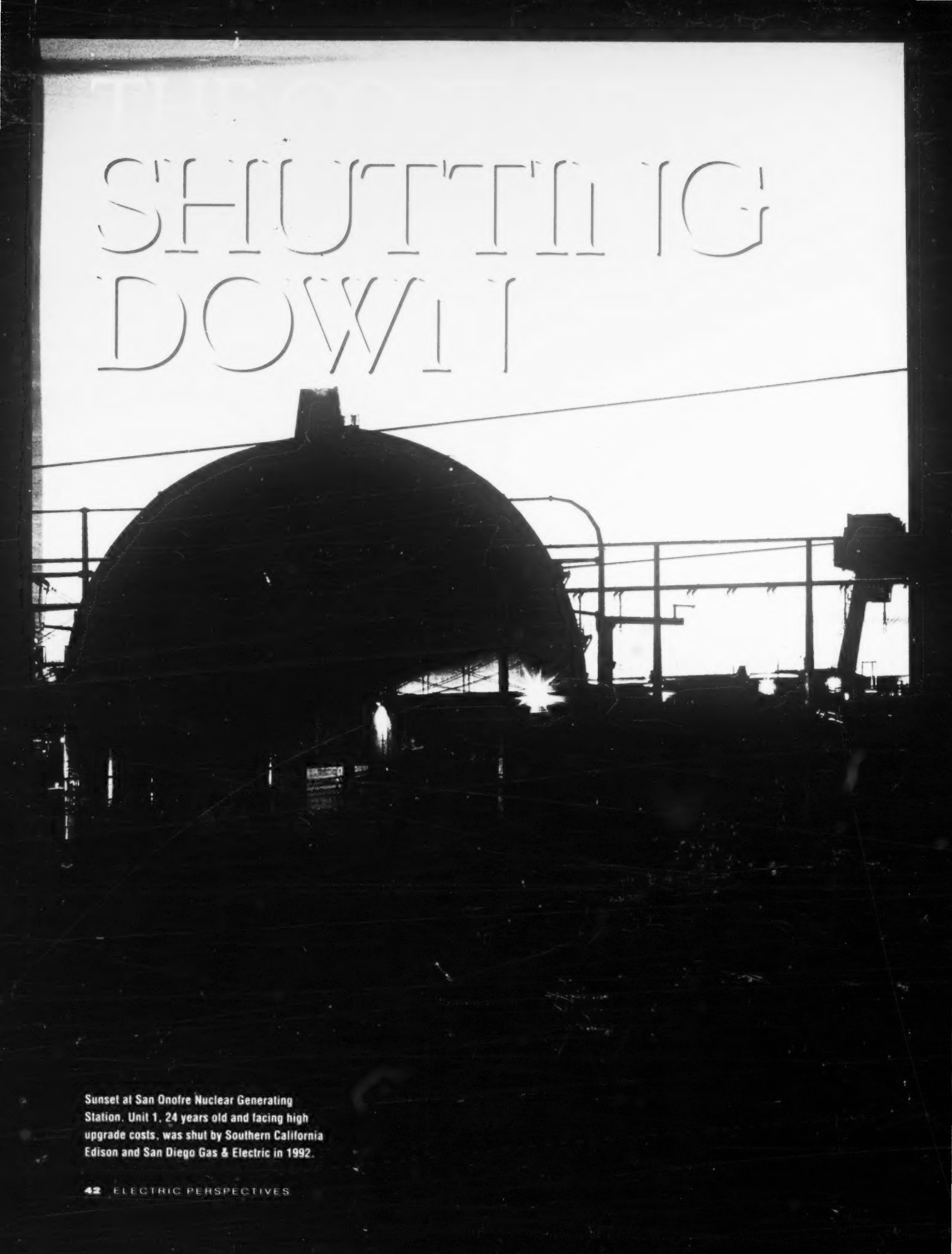
SHUTTING DOWN



Sunset at San Onofre Nuclear Generating Station. Unit 1, 24 years old and facing high upgrade costs, was shut by Southern California Edison and San Diego Gas & Electric in 1992.

BY MARVIN S. FERTEL

As we enter a new phase of nuclear power, what are we to do with unexpected decommissioning costs, escalating fees for waste disposal, regulatory uncertainty, and multimillion-dollar obligations? First of all, don't panic—the estimates aren't as bad as they seem.

When Yankee Atomic Electric Company announced last year that it would shut down its Yankee Rowe nuclear power plant, it named a decommissioning cost that was more than twice 1989 estimates. This was surprising for some, not so surprising for others, and still others were doubtful.

But it was not surprising at all that 1992's main topics of discussion between the nuclear industry and the financial community were the estimated cost for decommissioning a nuclear power plant at the end of its operating life and the arrangements for ensuring that the money is available when the plant shuts down. (See "The View from Wall Street," page 16.) Those discussions hang their hats on three main developments.

- Over the last 18 months, a number of utilities have revised their cost estimates for nuclear decommissioning. Almost all of the new estimates appear to be higher than the decommissioning costs contained in U.S. Nuclear Regulatory Commission (NRC) estimates by a factor of two or three.
- During 1992 the operators of three nuclear plants—Yankee Rowe, San Onofre Unit 1, and Trojan—made decisions to shut down their plants prematurely, before the expiration of their 40-year operating licenses.
- Over the next 20 years, the operating licenses for 32 existing nuclear plants will expire. (See Figure 1.)

Together, these three facts have created a great deal of uncertainty about what is involved in nuclear plant decommissioning and the financial implications associated with it.

- What should be included in the scope of decommissioning?
- Can we really estimate the cost of decommissioning?
- What about its impact on the cost of electricity?
- Will there be adequate funds available to decommission plants?
- Given recent experience, what does the future hold?

While meaningful questions and uncertainties about the final regulatory requirements and costs for decommissioning continue to exist, a large amount of the confusion and concern that recently arose can be clarified and resolved. Likewise, some of the remaining uncertainties can be put in better perspective.

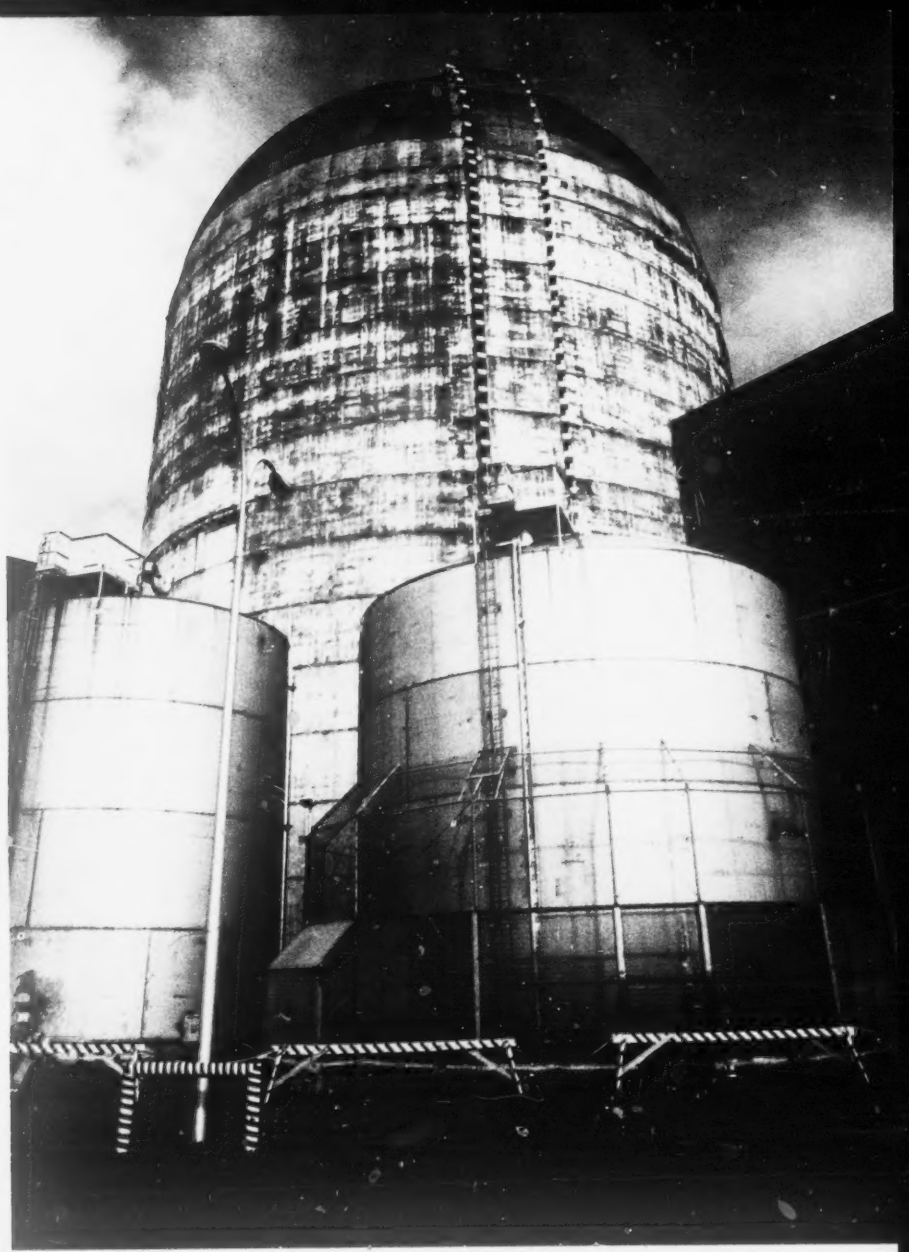
Defining Your Terms

As most people use it, "decommissioning" describes the activities performed to take a nuclear plant permanently

FIGURE 1

NUMBER OF NUCLEAR PLANT LICENSES EXPIRING PER YEAR, 2002-2030

Marc Gerstein is vice president, technical programs, at the U.S. Council for Energy Awareness.



In 1992, owners of Trojan Nuclear Electric Plant in Oregon announced its 1996 closing, citing the cost of new steam generators.

out of service. What is included in this term, however, has been one of the major points of confusion over the past year.

To begin with, the term is not unique to a nuclear plant. It can be applied to any type of generating facility (fossil-fueled, hydroelectric, and so on) when it reaches the end of its operating life. What is unique about decommissioning a nuclear plant is the fact that a specific and limited portion of the plant has been contaminated by radioactivity. The existence of radiation and contaminated materials directly affect the activities involved in decommissioning, its cost, and the regulatory requirements associated with it.

In the context of existing NRC requirements, decommissioning is fundamentally the removal and disposal of those portions of a nuclear plant (its physical facilities and site environment) that have been contaminated by radioactivity. The requirements focus on assuring that adequate plans and money are available to fulfill this objective. This seemingly limited scope reflects the NRC's regulatory responsibility to ensure that public health and safety are protected regarding the disposal of contaminated materials and any other hazardous wastes.

But, as a point of perspective, only about 15 percent of the volume of the materials—concrete, steel, equipment, etc.—at a nuclear site is actually affected by radiation. Therefore, in the context of NRC requirements, nuclear decommissioning focuses on a limited (albeit vitally important) scope of activities and related costs.

Clearly, the scope of activities contained under the umbrella of NRC requirements would not result in the dismantlement and removal of all structures and facilities from a nuclear site. Yet decommissioning costs sometimes are discussed in terms of "green field" requirements—that is, returning the site to its pre-plant state, which would require many more activities than those needed to remove and dispose of contaminated and other hazardous materials.

In most cases, if not all, such discussions are hypothetical. In essence, a powerplant site, nuclear or otherwise, is an important resource to an electric utility, and a difficult one to replace. Several aspects of the site are very valuable: a fully usable switchyard and transmission facilities; adequate cooling water sources and facilities; onsite administration, maintenance, and equipment storage facilities; and a surrounding community and infrastructure that supports and to a degree depends upon the existence of an electric generating station. It is highly likely that after a nuclear plant ceases operation, the site and its remaining facilities would still be used to support a new generating plant.

Reassessing?

Developed under the assumption that utilities would not have to bear the financial responsibility for spent fuel when plants shut down, current NRC decommissioning requirements do not address the green field issue. But over the last several years, as progress in establishing a permanent, high level waste repository has stalled, that assumption has been called into question. The premature retirement of Yankee Rowe, San Onofre, and Trojan

has further complicated the picture—and has somewhat skewed perceptions of the cost.

Where does the money come from to fund the disposal of spent fuel? The Nuclear Waste Policy Act of 1982 (NWPA) mandated a nuclear waste trust fund for that purpose. The money accrues from a 0.1 cent-per-kilowatt-hour (¢/kWh) charge added to the bill of consumers who use nuclear-generated electricity, and utilities that operate nuclear plants return that charge to the fund. The industry deposits a total of approximately $600 million per year.

Beginning in 1998, the U.S. Department of Energy (DOE) has the responsibility for using the funds to take spent fuel from nuclear plant sites and ultimately dispose of it. But right now there is no established storage facility, and DOE has yet to announce what compensatory measures it will take if it cannot begin accepting spent fuel five years from now.

Because NWPA gave DOE clear responsibility to dispose of spent fuel starting in 1998 and because a fund existed to achieve that end, NRC had not considered the cost for spent-fuel disposal as part of its decommissioning requirements. This cost, however, became a major issue for plants that announced intentions to shut down prematurely during 1992. In response, NRC staff has proposed to modify existing regulations so that within two years of a plant's premature shutdown, the utility will be required to provide the commission with a spent-fuel management plan, which must include the basis for funding spent-fuel storage and disposal. It is likely that this specific regulation change will be made during late 1993 or early 1994. On a separate track during this same period, NRC will evaluate whether or not it will require utilities to accumulate money for spent-fuel management as part of their decommissioning trust-fund requirements.

But adjusting those requirements raises the issue of double payment by customers. While it is within NRC's authority to ensure that adequate plans and money exist to manage spent-fuel storage and disposal when a plant

By Barry M. Abramson

When analysts and investors look at nuclear decommissioning, they look at financial risk. That's their job. But the financial risk associated with decommissioning a nuclear plant seems particularly difficult to define, both in terms of the ultimate costs and the timing of the payments.

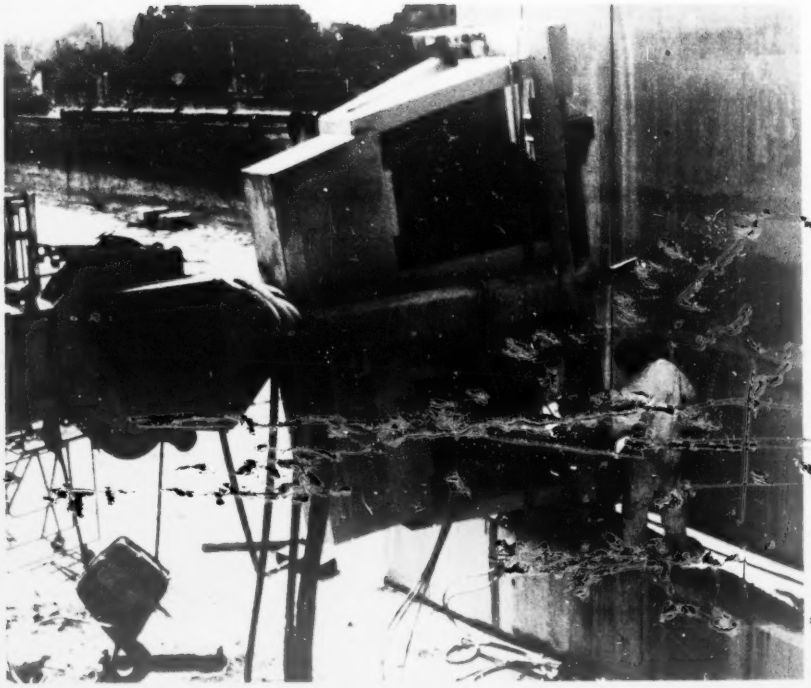
The reasons are several. First, utilities and engineering firms have very little actual experience with decommissioning large nuclear power units. Second, in recent years the estimates made by utilities themselves have been rising sharply. Third, over the last couple of years, a few plants have suddenly rescheduled their retirement dates, making them earlier than expected. And finally, and perhaps most importantly, utilities have made little mention of decommissioning costs during presentations to analysts. Although their investor-relations departments have done an excellent job of educating the investment community about various other financial and operating issues related to nuclear powerplants, they have failed to enlighten us fully about decommissioning.

So, the question of decommissioning costs presents Wall Street with financial uncertainty, and that means risk. And despite our far-from-complete knowledge, we must address it.

Things We Consider

The financial community assesses the risk associated with decommissioning in a number of ways.

- *How old is the plant?* In general (but these days, not always) we can assume that if the nuclear units are relatively new, the company may not have to incur decommissioning costs for several more years.
- *How recent is the utility's estimate of the plant's future decommissioning costs?* Any estimates more than a few years old are probably not a good indicator of the actual cost of decommissioning. Requirements change. And so does the value of the dollar. Most companies make their decommissioning cost estimates in current dollars. Consequently, an estimate made in, say, 1990 is probably based on 1990 dollars, but exactly how far will 1990 dollars go in, say, 2015?
- *How recently has the company been allowed by its regulators to increase the amount it charges in rates to fund its future costs?* Ideally, the company's rate recovery for decommissioning would be current with its most recent cost estimate. Sometimes state regulators can be shortsighted and are not so worried about the adequacy of the utility's funding for an event that is scheduled to take place more than a decade from now.
- *How does the company's estimate compare with estimates for similar nuclear plants of other companies?* That's often like comparing apples to oranges. One company might estimate $250 million for the cost to decommission a 1,000-megawatt nuclear plant in the year 2015. Another company's cost estimate for decommissioning a similar plant in the year 2010 might total $400 million. There are several possible explanations for the difference. Perhaps the estimates were made several years apart, reflect differing requirements, and are expressed in different dollar values. Perhaps the first unit is at a multi-unit site where economies of scale are expected to lower costs and the second unit is at a single-unit site. Then again, perhaps one of the estimates is flawed. That's what Wall Street wants to determine.
- *What kind of decommissioning do the costs cover?* Taking the plant to green field—the complete dismantlement of the unit and site restoration, known as DECON—is the most complete decommissioning process, but also the most costly. The less costly methods are ENTOMB, where radioactive contaminants are encased in structurally safe material, and SAFSTOR, where the facility is placed and maintained in a condition that permits it to be stored for future decontamination and unrestricted use.
- *How much is actually in the company's decommissioning reserve*



Only the fierce materials on a nuclear site are contaminated by radiation, and that narrows the focus of activities and costs.

as of the most recent reporting date? Whatever the reasons, some companies appear to be more underfunded than others.

What About Surprises?

Many investors simply assume that the utility will deal with decommissioning several years from now, which means that it is well beyond their typical investment horizon. Rightly, they consider decommissioning costs to be part of the total cost of producing electricity from nuclear plants, costs that should ultimately be recovered from electricity customers. Also, they judge financial and regulatory risks to be low for companies whose nuclear plants operate for 30 years because they assume that the companies will accrue adequate decommissioning reserves.

But that's the comfortable and distant horizon. From Wall Street's vantage point, the major risk regarding decommissioning is premature retirement. When this happens, the utility may need to go before its state regulators and request an immediate increase in the amount it collects from electricity customers for decommissioning. Most analysts appear to believe that state regulators will allow decommissioning costs to be recovered from customers eventually, even though there is a risk of regulatory lag in that recovery. But there's another less obvious risk under this scenario: Utilities may have to deal with unwanted regulatory scrutiny of other factors such as the company's current return on equity and level of overall earnings.

Moreover, with the rise of least-cost or integrated resource planning, there's a good chance that soon regulators in every state will force utilities to consider alternatives before making a large financial commitment to overhaul a nuclear plant. And that will increase the likelihood of early retirement.

It's a chance Wall Street cannot afford to ignore. Investors need to determine the probability that a company's nuclear unit or units may be subject to an early retirement and then compare that probability to the level of the company's underfunded future decommissioning cost. For example, if the probability of early retirement is high but the underfunded decommissioning cost is not large, the financial risk may not be high. Likewise, the financial risk of a premature retirement is less severe when there is another nuclear unit still operating at the same site. Even if one unit is retired early, most utilities would wait until the last unit at the site has reached the end of its operating life before they would begin to decommission any of the units, giving the company more time to accrue funds for decommissioning the unit that was retired early.

Who's Ready to Go?

More than 50 operating nuclear units in the United States are at least in their mid-teens, but it is very difficult to predict which of them will face early retirements similar to San Onofre Unit 1 and Trojan. Some well-run nuclear units could face early retirement in the next few years purely because of economics. Good maintenance programs can slow down aging, but eventually things just wear out and must be replaced, even at the plants with the best operating records.

On the other hand, one can't simply make a list of nuclear units that have had difficulties during their operating history and label these as the most likely candidates for early retirement. Some of the troubled nuclear units from a few years ago are now operating extremely well.

A fair estimate, given what we know today, is that about a fifth of these aging units could face premature retirement over the next few years. Their fate is attached to rising nuclear operating and maintenance costs and the high cost of major plant overhauls, as well as to their position relative to other power-supply alternatives. Cheap natural gas, excess capacity in some regions, over-building by independent power producers, and greater wholesale transmission access imparted by the National Energy Policy Act of 1992 may well price some nuclear units out of a job.

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Estimates become less awesome once they are put in perspective. Table 1, which breaks down decommissioning estimates for Yankee Rowe, provides a good example of the impact of decommissioning "scope."

- The cost for spent-fuel management increased the estimated NRC-required base cost for decommissioning the plant by almost 40 percent.
- The cost to bring the site to greenfield is relatively small, representing less than 10 percent of the base decommissioning cost—and even at that it remains hypothetical.
- The $42.7 million estimate for site maintenance reflects an eight-year period for preparing the decommissioning plans, mobilizing to decommission the facility, and performing other actions associated with a premature shutdown as you reduce staff and discontinue operating license required activities. This magnitude of additional costs would not exist, however, if the plant entered the decommissioning phase in an orderly way at the end of its full operating life.

TABLE 1

YANKEE ROWE DECOMMISSIONING ESTIMATES
(1992 dollars)

NRC Estimate According to NRC Formula

Additional Costs Included in Above Estimate

TABLE 2

NRC DECOMMISSIONING FUNDING REQUIREMENTS

Minimum funding required	1986 dollars

The utility must update the funding requirement annually.

Cost Estimating Is Not Rocket Science

As part of its 1988 regulations, NRC had included an estimate of the minimum amount of money it required utilities to have available for decommissioning their nuclear plants. As noted in Table 2, a utility is expected to update its estimate annually, based on increases in the costs of labor, energy, and waste disposal.

But two events in 1992 created considerable uncertainty about the industry's ability to make acceptable, accurate estimates.

First, the state of South Carolina decided that while the Barnwell low-level waste disposal facility would remain open to receive waste, the state would impose a significant surcharge of $2.20 per cubic foot of waste received from outside the Southeast Compact Commission states. In comparison to 1991 costs, this surcharge increased the cost of waste disposal at Barnwell by a factor of five.

The second event was the decommissioning estimate prepared after Yankee Rowe's premature shutdown more than twice the previous estimate. While the estimate reflected some of the scope changes (such as spent-fuel storage), it also factored in the new and much higher cost for low-level waste disposal. A number of other utilities announced that they had updated their estimates as well and that costs had increased two- and threefold.

Media stories and anti-nuclear groups created the impression that decommissioning costs were soaring out of sight and could not be accurately gauged. But the argument for out-of-control complication and inflation is a fallacy. In fact, while there are valid reasons (like increased labor and waste-disposal costs) for the estimates to increase, the basis for determining an estimate is not rocket science.

Over the last decade both government and private-sector contractors have developed valid and comprehensive methodologies for estimating the costs to decommission a nuclear plant. The methodologies

- require accurate information on the amount of material (that is, piping, pumps, motors, concrete, and so on) that must be decontaminated or disposed of as low-level waste;

- include appropriate factors that recognize the degree of difficulty in performing certain activities because of the presence of radiation, small working areas, etc.;
- recognize the fact that working in a radiation environment requires extra labor hours for training, health personnel, etc.; and
- are based on the vast amount of as-built plant drawings and the real experience the industry has in performing work at the plants during outages.

The actual physical work performed during decommissioning, which includes such activities as removing equipment, cutting up pipes, and removing layers of concrete, is certainly less challenging than the installation of new equipment during the time the plant was operating.

Based on the fundamentals of those methodologies, the NRC developed its general equation for updating the minimum required funding level.

Looking at the equation in Table 2, you can see that low-level waste costs make up about 22 percent of the total estimated cost. Therefore, if the new Barnwell waste-disposal cost (again, about five times the 1991 cost) were factored into the NRC equation and nothing else changed, the estimated total cost would about double. That may seem like a wild escalation and to portend ill, but in reality it has nothing to do with the ability to estimate.

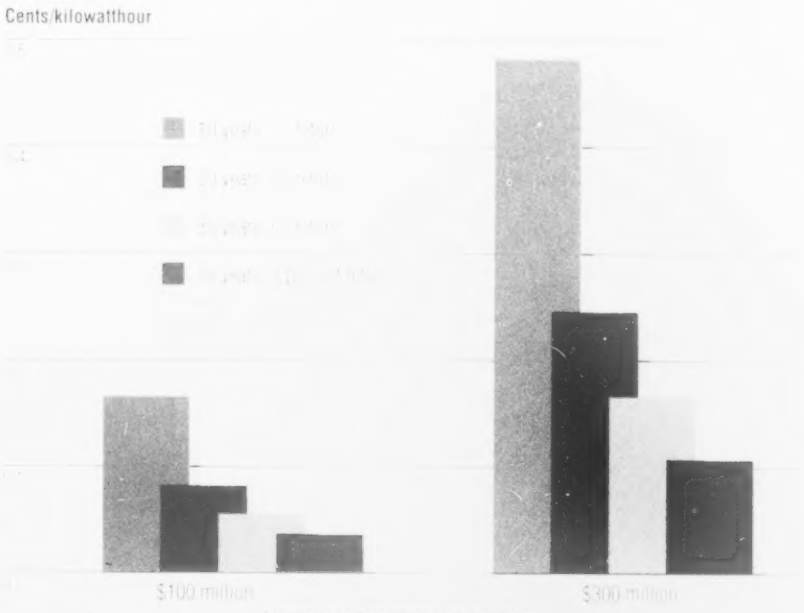
And there are mitigating factors for the rise in disposal costs. First, it is worth noting that the new Barnwell bottom line is much greater than the real cost of disposing waste there (or at Washington state's Hanford facility, the nation's other operating low-level waste disposal site). Also, as the cost for waste disposal increases, the approach to decommissioning a plant moves more toward maximizing waste reduction and using decontamination techniques, thereby reducing that cost. Furthermore, as the expirations of operating licenses approach, we should expect significant improvements in de-

Rising costs for the disposal of low-level wastes should increase competition and propel technology to *reduce* those costs.

FIGURE 2

IMPACT OF DECOMMISSIONING REQUIREMENTS ON ELECTRICITY PRICES

For a 1,000-megawatt plant running at a 70-percent lifetime capacity factor



commissioning technologies and more competition in the business. From a cost-estimating perspective there is no reason to believe that accurate estimates cannot be prepared. Likewise, there is no reason to expect that the increase in Barnwell disposal fees represents a trend toward ever-increasing costs. In fact, while it is likely that new low-level waste facilities may charge fees comparable to Barnwell's, waste-reduction techniques and other competitive forces may also act to mitigate unreasonable growth in those fees.

Only Minor Increases In Electricity Costs

With the growing competitive nature of the electric utility industry, a significant concern about increased decommissioning costs is the impact on the cost of electricity. Currently, funding of the decommissioning trust fund has a minor effect on electricity prices to customers, adding between 0.1 and 0.2 ¢/kwh. But what would happen if the decommissioning funds required were to increase significantly?

Figure 2 shows the estimated impact of increases in decommissioning costs on electricity prices. For example, if we assume an average remaining operating period of 20 years, a $100-million increase in decommissioning costs would increase prices by less than 0.1 ¢/kwh. Even with a $300-million increase in decommissioning costs (an enormous assumption), the electricity price would only go up just over 0.2 ¢/kwh. While we cannot underestimate the competitive challenges facing operating plants, it does not appear that reasonable and likely increases in decommissioning costs would radically affect the competitive situation.

Will the Money Be There?

NRC requires that a utility establish a decommissioning fund for each reactor. Both the amount of money required for decommissioning and the adequacy of the fund to accumulate it must be reviewed annually by the utility. As stated previously, the fund's size is adjusted periodically to account for increases in the costs of labor, energy, and low-level waste disposal.

NRC requirements allow the fund to take the form of an external sinking fund, a surety, insurance, or other guaranteed funding method, or a prepayment deposited prior to operation. In many states the public utility commission may require the utility to invest primarily in state-issued financial instruments. The National Energy Policy Act of 1992 removed the so-called black-lung restrictions (for the similar fund which the coal-mining industry has to protect pension funds for miners) on where utilities could invest decommissioning trust fund money. At the same time, the federal tax rate on the fund was lowered from 34 percent to 22 percent in 1995 and 20 percent thereafter. Depending on the nature of the holdings in the fund, just the reduction in federal tax rate could effectively increase the rate of return up to 21 percent. The removal of the black-lung investment restrictions should also contribute to improving the funds' financial performance, even with the expectation that the funds will be invested conservatively.

The plant closings in 1992 raised questions about whether there would be adequate money in a plant's decommissioning fund upon its shutdown. Of course, the changes in the estimates caused concerns that the utilities were not collecting enough money. Also, the trust funds appeared generally to be underfunded, even for estimates that had been made before 1992. For a plant shutting down prematurely, it was clear that the fund would be deficient, and there were nervous questions about how the utility would raise the money to decommission the unit.

The explanation for the apparent underfunding lies in the nature of how most of the funds work. In general,

they accumulate money in such a way that the compounding interest drives their greatest growth during the later years. For example, assuming an interest rate of about 6 percent, only about half of the desired funding would accumulate over the first 30 years, with the remaining half of the fund growth taking place over the last decade of the plant's 40-year operating license. Many of the existing plants that are not even halfway into their operating license may have accumulated only 10 to 20 percent of the total fund requirement. Thus the concern about underfunding stems from the somewhat simplistic view that the amount of money in the trust fund should directly correlate with the amount of time the plant had operated out of its license multiplied by the total amount of money required for decommissioning.

But some estimates, for a number of reasons, go beyond what's covered in the funds at a particular time. For plants that shut down prematurely in 1992, both the Federal Energy Regulatory Commission (FERC) and public service commissions found it appropriate to allow the operators to recover the necessary decommissioning costs in electricity rates. In the case of Yankee Rowe, FERC ruled that the required money could be recovered in rates. While final decisions on both Trojan and San Onofre Unit 1 are still pending with state economic regulators, it appears that in both cases the necessary decommissioning funds will be allowed in rates. And, in a decision by the Pennsylvania Public Utility Commission, recovery of decommissioning costs related to the damaged Three Mile Island reactor was also allowed.

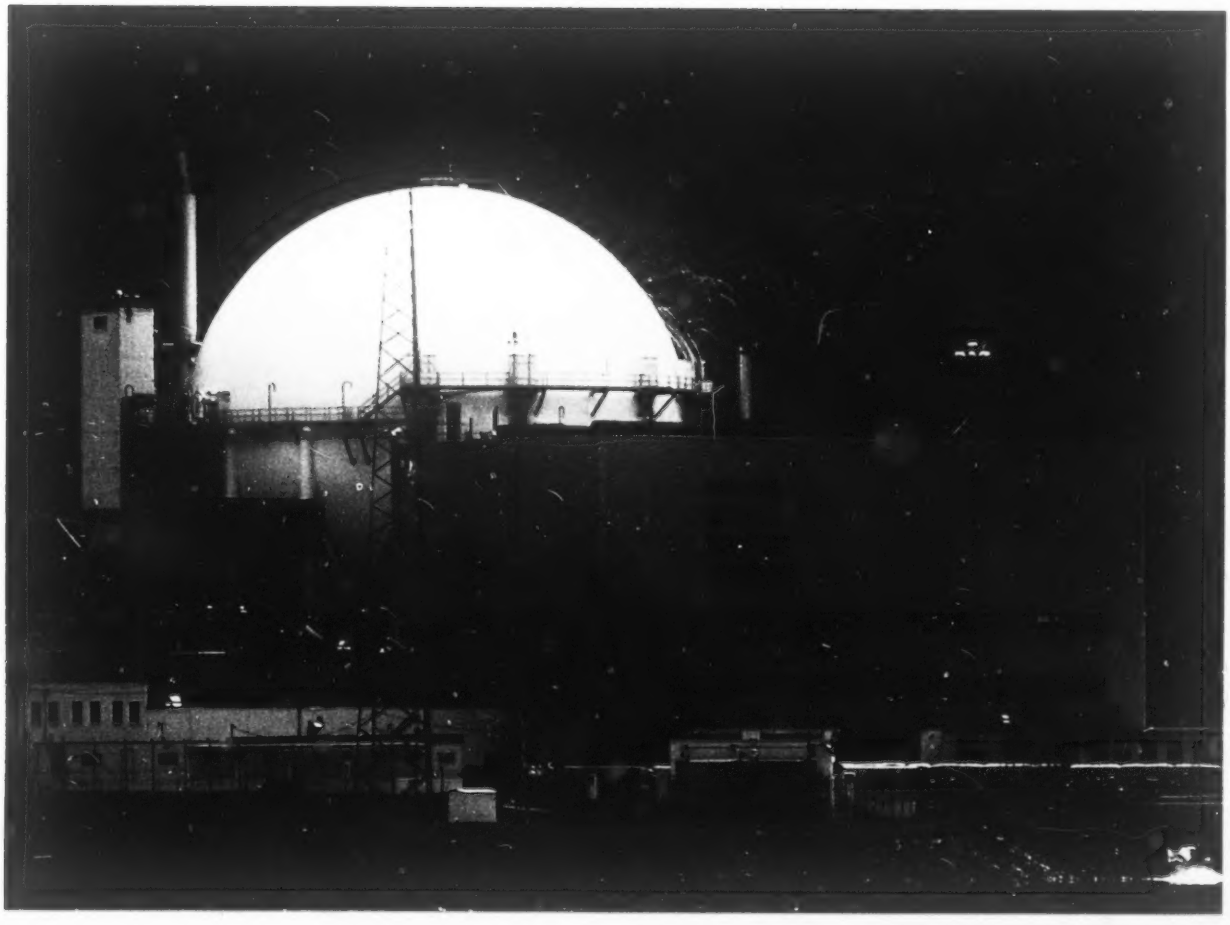
While uncertainties always exist, it appears to date that regulators have taken reasonable actions to provide utilities with the necessary money to fund decommissioning activities.

Seeking Clarification

During the next two years, the nuclear industry and everyone else concerned with decommissioning costs can expect action on a number of fronts:

- *NRC will have updated its estimates*

Yankee Rowe nuclear plant—at the time the longest-running commercial power plant in the U.S.—ceased generating in February 1992.



for decommissioning nuclear plants. This information will be used to modify the existing NRC requirements as part of a rulemaking activity during 1994. Preliminary results from discussions last summer indicated that depending on low-level waste disposal costs, the base cost will decrease from the earlier NRC estimates.

- *DOE will soon announce plans for fulfilling its obligation to take spent fuel by 1998.* This plan's content could influence the cost for handling spent fuel at plants that prematurely shut down.
- *NRC will complete its assessment of the need for utilities to fund spent fuel management costs as part of their decommissioning requirements.* It is not expected that such additional funding requirements will result.
- *More progress in the siting of low-level waste disposal facilities will be seen.* There will be greater clarity regarding the costs charged by operating sites.
- *NRC is pursuing a rulemaking to clarify its site-cleanup requirements.* This provides an opportunity to clarify the requirements and to identify other requirements that result in safe but realistic standards.
- *All nuclear plant operators will have reviewed their existing decommissioning estimate and funding strategies.* They'll have new opportunities offered by relief from the black-lung restrictions in the Energy Policy Act.

And many utilities are also preparing plant-specific estimates for decommissioning their units.

Whither Decommissioning?

Nuclear energy is currently the second-largest source of electricity in the United States. The nation's 109 operating nuclear plants generated 618 billion kilowatthours during 1992. While they've been a steady part of the generation picture for the last few decades, they are about to enter their next phase of challenges.

Those challenges include controlling operation and maintenance costs, deciding on the desirability of renewing an operating license, and finding a place to store or dispose of spent fuel and low-level waste. To the degree that these challenges are overcome, decisions about decommissioning become easier. In the next couple of years, we should expect progress in the elimination of many uncertainties related to decommissioning, from the perspectives of both regulatory and funding requirements, and that should make those decisions easier still. ◆

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Cutting *the* Price *of* Health Care

BY JOHN S. SPARKMAN

NATIONAL OBLIGATION and progressive social policy are persuasive arguments for legislation that ensures health-care coverage for every citizen. But federal legislators and business executives might do themselves and their constituents, shareholders, and employees a favor up front and look at it also in terms of the other driving force, which is perhaps the overriding one—cost.

The federal government already spends $258 billion a year on health care—almost one-fifth of the federal budget—so controlling annual cost escalation (currently in the range of several times the consumer price index) is critical to any effort to curb the growth in the federal deficit. For U.S. corporations in general, which provide health-care coverage to a third of the population (but whose payments tend to cover the costs of others also), the figures are staggering as well. According to the July 1993 *Harper's* magazine "Index," which derived its figure from U.S. Department of Health and Human Services statistics, health-care spending by U.S. corporations in 1992 was 8 percent more than total net corporate profits.

For utility executives, reform is especially critical. Failure to halt the escalating costs could mean declining profits for shareholders and reduced benefits levels

John Sparkman is federal affairs representative for Baltimore Gas & Electric Company. He previously was a staff member of the U.S. House of Representatives.

for employees. The industry's health care costs between now and 2000 (assuming 572,514 employees and using the Government Accounting Office's projected rate of increase of 16 percent) will total $43.9 billion. And even if the rate of annual increase is held at the consumer price index (4 percent) the bill will be huge: $25.3 billion. (See Table 1 for annual statistics.)

Cost is a compelling issue. Reform that extends health coverage to the uninsured or underinsured is admirable and necessary, but alone it also has a depressing bottom-line effect for both business and government. True reform also controls cost.

Reform from the Payer's Perspective

The investor-owned electric utility industry generally provides a very attractive benefits package to its employees, and in order to attract and retain a quality workforce it is desirable to continue to do so. But the costs of providing these benefits is escalating beyond acceptability, and new competitive forces, brought about by restructuring and an erosion of regulated monopoly status, will further limit the industry's ability to provide these levels of benefits in the future.

Recognizing those facts but without attempting to adopt a particular reform proposal, Edison Electric Institute's (EEI's) Health Care Task Force identified six principles in the reform debate that are particular to our industry but applicable to the larger universe of companies that provide insurance for their employees. Because utilities are purchasers or "payers" of health care (as opposed to providers or insurers), these "Payer Principles" focused solely on items of concern to purchasers.

- National comprehensive reform that addresses cost, access, and quality is the only acceptable solution to resolving the health-care crisis.
- Legislation must contain clear and effective provisions for controlling the increasing costs of health care. An acceptable level of increase might be linked to the consumer price index (CPI). And cost-control provisions should seek to insure that health care costs consume no higher level of gross domestic product than in 1992.
- Payers should continue to be responsible for providing access to health care for employees.
- Payers should continue to play a major role in the management of any health care program initiated.
- The current practice of cost shifting from the public to the private sector (i.e., payers picking up the cost for the uninsured and underinsured) must become visible.
- Administrative reform (e.g., streamlining the reimbursement process with the use of a single claim form) must be part of any comprehensive reform package.

From these principles, the industry's policy position on health-care reform was formulated. It recognizes the necessity to control costs and maintain coverage and advocates a reform package that is employer-based but comprehensive in scope. (See "The Industry Considers Health Care Reform," page 61.)

Reform and Revamp

And to control costs, our industry has no choice but to promote health-care reform actively. No longer can it be a matter of resisting government mandates or leaving it up to others to fight the cost battle. Our companies literally cannot afford to continue paying for health-care costs that grow at four times the rate of CPI.

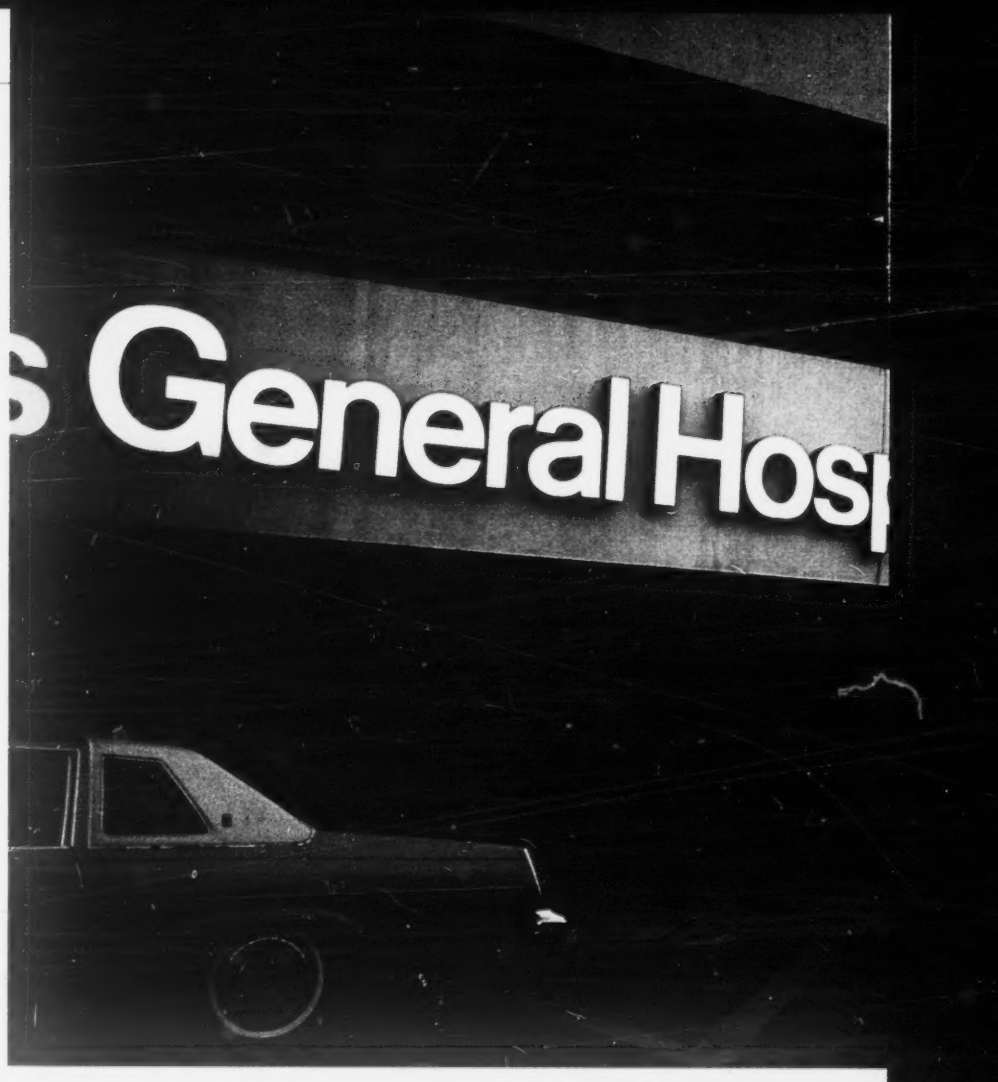
Make it comprehensive. The right reform package would address access, quality of care, benefits, the role of payers (employers), and cost containment. For example, tort reform may lessen the malpractice insurance burden for doctors and perhaps drive down costs for payers, but tort reform by itself is probably only a part of the picture.

Piecemeal solutions and incremental approaches may only exacerbate the problem. We have seen attempts by Congress and by the various states to improve upon the current system, only to find that these "reforms" sometimes work at cross purposes. Examples include Congress' effort to reform Medicare to require larger copayments by wealthy seniors, or to curtail Medicaid payments to states not meeting certain requirements. These well-intended reforms either met strong and effective political resistance, aiming at affected groups, or encouraged additional cost shifting. The pervasiveness of the problem demands comprehensive treatment.

Make it universal. The expansion of health-care coverage should help to control costs by eliminating cost shifting, which increases the overall cost of health care to employers who provide the actual coverage. Fees charged to Medicare or Medicaid patients often are lower than the actual cost of service; fees to the uninsured may be waived or uncollected. When that hap-

HEALTH-CARE COSTS FOR ELECTRIC UTILITY INDUSTRY
Assuming $3,600 per employee for 572,514 employees

	1991	2000	2000
Annual rate of increase	n/a	4 percent–CPI	16 percent



pens, costs for the insured or those able to pay are increased to make up the loss. Universal coverage would end this practice by distributing costs more equitably.

Utility executives advocating universal coverage while facing a potential cutback in benefits for their own employees will find justification—if not comfort—in the reality that, without universal coverage, they would be reducing those benefits even further. As some have posited, we already have universal coverage, because virtually everyone in this country who requires health care will get it. What we need is universal payment.

Make it quality-driven. To monitor and streamline the delivery of products and services (and therefore cut costs), business has used continuous quality improvement programs. These can be applied to health care to cut down on unnecessary services, improve patterns of practice, and reduce abuse of the system. One oft-cited way of improving care quality is to establish a database to which all providers can have access, so that they can evaluate various courses of treatment. Incredibly, physicians and other providers have remarkably limited exchange of information on treatment. In the information age, it is unacceptable that medical professionals not have a more advanced information-sharing electronic network.

In addition to providing medical information, such a system would include information on the cost of health care from various providers in order to help consumers make informed buying decisions.

Keep and Confirm

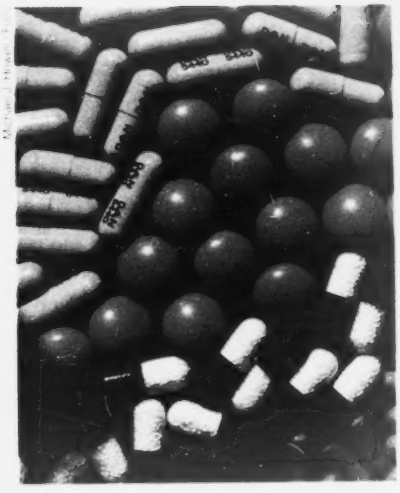
Maintain ERISA preemptions of state law. The Employee Retirement Income Security Act (ERISA) is a federal law governing pensions, but it has some important jurisdiction in the area of health care for self-insured companies. Foremost, ERISA assures federal preeminence in health-care benefits and provides that companies operating across multiple states (as many utilities do) generally will not be subject to differing benefits requirements in those different states.

For a number of years, states such as Hawaii and Maryland have imposed minimum requirements on employer-provided health-care plans. For an employer operating in several states, meeting the benefits requirements of differing states is a costly administrative problem. It also raises the issue of equity among employees.

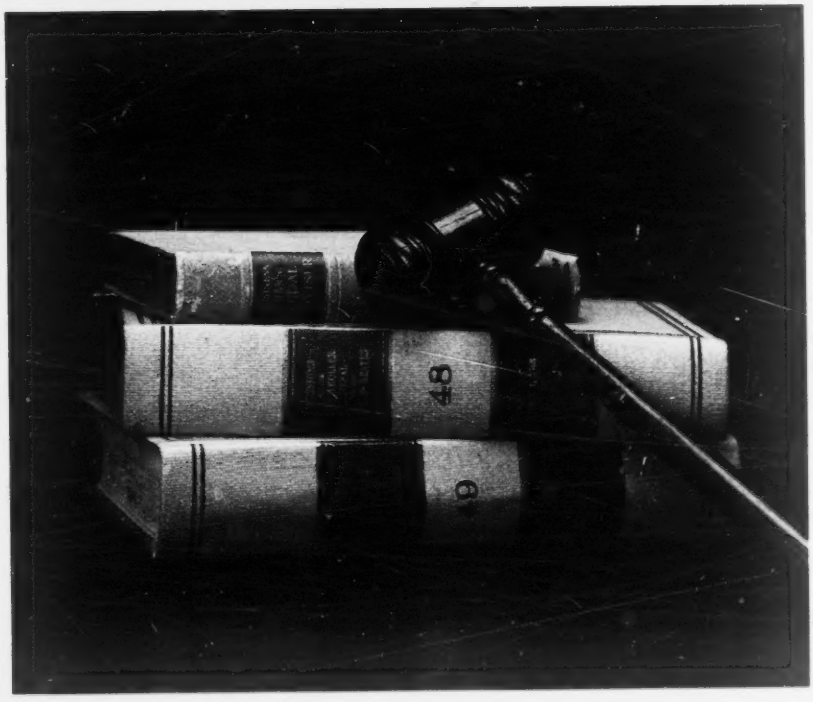
There's also a broader argument against individual states creating their own health-care mandates. While such mandates are commendable efforts to assure coverage and control costs, adequate health-care coverage is a national problem requiring a national solution. When a resident of Maryland who has sufficient insurance moves to another state with no mandated benefits and cannot afford coverage, the nation continues to have a problem. If a vacationer with a state-run benefits package requires treatment in another state where his insurance is not honored, the nation continues to have a problem.

Additionally, ERISA as it stands assures that states may not tax self-insured companies on the premium value of their benefits packages. Although a tax would be an additional source of revenue for the states, it would impose costs on employers who are trying to do the right thing in providing health-care benefits. The possible result of ERISA exemptions would be reduced benefits to employees.

Maintain management's decision-making power. The right reform would also allow employers the flexibility to take steps to control the costs of those benefits. Such steps might include requiring employees to contribute to the cost of their insurance, as well as to be responsible for a copayment or deductible. Premiums, deductibles, and



Payers vie with groups more active than they but less apt to focus on cost control in reform—doctors, medical and drug manufacturers, insurance and legal interests.



copayments will necessarily vary from company to company and may necessarily increase. As is now the case, these decisions may be made by the employer independently or through collective bargaining, but employers must have these means of holding down cost increases.

Should reform result in a national health-care system whereby employers must purchase insurance through a collective entity (such as a purchasing cooperative, mentioned in some managed-competition proposals), they must have representation in the entity's management. Otherwise, the parties responsible for paying for most of the services would not have a major voice for cost control, and their interests would not be protected.

Keep the funding mechanism fair. Perhaps most important from the payer's perspective is to have a national health-care funding mechanism that does not make employers pay more than they're now paying to insure their own employees. Also, a utility may wish to provide its employees with more coverage than the government minimum—and it needs the flexibility to do so. There are various potential

funding mechanisms to pay for coverage to the uninsured or underinsured. It is not our charge to design that mechanism. What the industry can justifiably say, however, is that we are doing our share already by providing excellent benefits packages that include a broad array of coverages and complementary services. We're very proud at Baltimore Gas & Electric, for example, of our onsite clinics that provide preventive and primary care to employees. Whatever funding mechanism the nation adopts, the industry will be willing—and want to have the freedom—to continue taking care of its own employees.

Washington Plays Catch Up

Reform of the health-care system is hardly a new topic, but given that it took Congress 20 years to enact a Medicare program, it should not be too surprising that the progress has been slow. It is an incredibly complex issue, with numerous Congressional committees of jurisdiction and a multitude of established and *ad hoc* lobbying groups involved.

Now—as of the time of this writing in July—it appears that cost may finally drive government officials and business leaders to action, but the federal government is behind the curve on this one in another way. Several states already are ahead of Washington on this issue, and it is state-level action—driven in part by state costs and in part by market forces—that may require Congress to act sooner rather than later. As conflicting state plans (albeit thoughtful and innovative) are implemented, they will create a patchwork of contradicting regulations and costly administrative problems for both payers and providers. Just this Spring the problem was exacerbated as the budget reconciliation bill adopted by the House of Representatives offered waivers of ERISA's federal preemption language to four states. Should this bill become law, 14 states will have some type of ERISA waiver, allowing them to pursue limited cost-containment measures (as in Maryland) and possibly a full-fledged Canadian-style, single-payer system, where the government is responsible for all health-care coverage—as proposed in Vermont and California.

We are a highly mobile society. One can imagine the complications these highly specific and different state requirements will impose on the delivery of care.

In fact, portability of coverage is a theme of the major reform proposals being floated in Washington, even those plans that would give states considerable authority and flexibility to develop their own particular programs. The most far-reaching legislative proposal along these lines so far—is that sponsored by Representative Jim McDermott (D-Washington). His bill (HR 1200, the American Health Security Act) is an unabashedly Canadian-style, single-payer scheme.

On the face of it, the bill has many attractive features.

- It would provide universal coverage in a system that is federally financed but administratively decentralized to the states.
- Global budgets would help to rein in costs, yet patients would continue to have the option of receiving care through a managed-care arrangement (such as a health maintenance organization) or their choice of physicians or hospitals.
- All providers would bill the states for services, with HMOs presumably operating within an annual budget and pri-

Baltimore Gas & Electric's onsite clinics are an example of employee health benefits that utilities need the freedom to offer.

vate providers receiving payment on a fee-for-service basis.

- The bill would promote data collection and information sharing to help providers control costs and to inform consumers on the quality and cost of various providers.
- The benefits package would be generous. It would include inpatient and outpatient hospital services, professional care by state-authorized providers, community-based health services, nursing services, home health care, hospice care, prescription drugs, diagnostic tests, chemical-dependency treatment, mental therapy, ambulance service, prosthetic devices, and numerous other services. No deductible or copayment would be required or permitted for acute or preventive care. At their discretion, the states could provide additional benefits.
- An American Health Security Standards Board would set overall standards and budgets and provide guidance to the states on such matters as reimbursement rates. A subgroup would collect data on outcomes research and practice guidelines. States would be required to participate in a national uniform electronic database for all patient records, while protecting patients' privacy.
- States generally would receive government funding equivalent to 85 percent of their needs to finance health care—they would be responsible for funding the remainder. Medicare, Medicaid, the Federal Employee Health Benefits Program, and insurance for the military would be folded into the new system.

The Congressional Budget Office (CBO) estimates that such a system could extend coverage to all Americans and still reduce total annual health-care expenditures in this country by $14 billion (based on 1991's expenditure of $748 billion). For some employers, particularly those providing the total share of health-care coverage with no employee contribution, such a proposal is attractive: It would help to contain overall costs while specifically relieving companies of some portion of their employee health-care outlays.

The utility industry, too, might find it attractive were it not for HR 1200's financing mechanism. In its most startling provision, the proposal would increase the corporate tax rate to 38 percent. The impact of this 4-percent increase would be substantial. The budget reconciliation package moving through the Senate this summer projected that a 1-percent increase in the corporate tax rate would take $16 billion out of the economy over a five-year period.

Moreover, HR 1200 proposes significant increases in personal income taxes at all levels, a surtax on the wealthy, and numerous other revenue provisions that involve elimination of existing tax deductions and an increase in the tax burden for Social Security recipients and current Medicare beneficiaries.

That's a wallop of a tax bill.

Arguably, the costs would remain the same. Businesses would be simply shifting expenditures for their current employee-benefits programs to the federal tax collector, who will arrange for the employees to receive health care through the single-payer system. And though employees may face higher income taxes, they will no longer be required to help fund their insurance or to face deductibles or copayments for most services.

But in too many cases the costs don't balance out when individuals or businesses do their own calculations of this transfer of funds. Some utilities that have studied the McDermott proposal find that they would end up paying more than they currently do through self-insurance or privately obtained insurance. Others find that the cost would be less. But, in any event, the quality of benefits would tend to be lower, and raising that quality has costs, too. For example, as attractive as the minimum benefits package of HR 1200 is, it does not include dental care (other than pediatric service).

HR 1200 is a major improvement over many single-payer proposals, particularly as it tries to assure portability, offer attractive benefits, and preserve individual choice in providers of care. But many businesses and individuals will oppose it unless it preserves the option of self-insurance or privately obtained insurance, which may be less expensive. The problem for the bill's proponents is that there isn't much room for maneuvering in the legislative process. As an example, if the various federal and state health programs (Medicare, Medicaid, Federal Employee Health Benefits Program) were folded into a single-payer system but the right of private insurance were preserved for others, the CBO estimates no savings from such a system, but rather an increase of $23 billion over 1991 actual expenditures.

The industry policy grew out of the study and findings of EEI's Health Care Task Force, which spent 10 months reviewing utility industry expenditures for health care and measuring industry costs against those of other businesses. The EEI Board of Directors approved the final policy statement at the Annual Convention in June:

"EEI favors health-care reform which includes clear and effective provisions for controlling costs. Reform should be comprehensive, assure universal coverage and improve the quality of health care delivery while maintaining existing ERISA preemptions of state laws. To the extent they presently do so, employers should maintain the ability to manage the cost of the benefits they provide. Recognizing that many employers may choose to provide coverage beyond that required by any government mandate, any funding mechanism for extending coverage to the uninsured or underinsured should not impose upon employers total costs beyond those of insuring their own employees."

We'd get universal coverage, but no cost savings. Beyond that aspect, there is little in the bill that would institute long-term cost-control mechanisms. Savings realized in early years following enactment might evaporate as total spending continued to escalate at rates well in excess of CPI.

McDermott recently acknowledged that the financing provisions of HR 1200 will require revision, but we have no indication of the nature of those changes. We do know that several of McDermott's original ideas for financing have been coopted by the President's deficit-reduction package, which has been before the Congress this year.

President Clinton speaks to the health-care task force, led by Hillary Rodham Clinton. The President's reform plan is due in September.

Getting at Managed Competition

The other major legislative proposal, albeit one far less sweeping, is that offered last year by Representative Jim Cooper (D-Tennessee). The Cooper bill (HR 5936 in the 102nd Congress) is titled the "Managed Competition Act." It has not yet been formally reintroduced in the 103rd Congress, but the bill is attractive to the utility industry for several reasons. It offers universal access, administrative reform, and cost containment while building on the existing employer-based approach.

"Managed competition" is the hybrid the name suggests. It is neither totally free-market nor government controlled, and, depending on who's talking about it, it has more of one and less of the other. In essence, it combines artificially induced competition through the use of purchasing cooperatives made up of all buyers and providers within a region. Within the cooperatives, providers' information on costs and quality of service would be available to buyers, who could select their care provider. The idea is to create competition between providers in order to hold down costs.

- The cooperatives would make insurance affordable to small businesses through lower rates than are available to the businesses individually. A new federal program would subsidize the health-care premiums for low-income individuals or families.
- The bill has no employer mandates but relies on tax incentives to encourage formation of and participation in regional purchasing cooperatives. The cooperatives would buy insurance for their members, and plans would not be allowed to exclude coverage for preexisting conditions or charge higher rates for participants with a history of higher medical expenses.
- A national board would establish a minimum benefits package, which all health plans would be required to adopt. Employers could offer more generous benefits, but only the minimum package would be deductible for tax purposes. The employee would have to make copayments—the intention is to make health-care consumers cost-conscious.
- The system would encourage preventive health practices, provide for malpractice reform, and reduce paperwork by developing a standard, electronically transmitted claims form.

In all likelihood, the Cooper bill is not much different from the managed competition particulars of the Clinton plan, which remains under design. What is unclear about Cooper's proposal is whether it encompasses enough elements of the health-care system to have the desired impact on cost control, and whether the overall savings combined with any additional taxes generated would be sufficient to cover the costs of subsidizing coverage for the uninsured.

The bill has lots of possibility from the perspective of the utility industry. It preserves ERISA preemptions from state-mandated benefits, gives employers flexibility in the type of benefits offered, contains costs through administrative reforms and competition between providers, and encourages improvements in the quality of care delivered. It is arguable, however, whether the bill would assure universal coverage.

What Can We Expect?

During last year's presidential election, both Bill Clinton and George Bush embraced to varying degrees the theory of managed competition. The payer community, interestingly, has been all over the map on this one, with most businesses adopting their usual antipathy toward any government mandate, although some major employers have endorsed the Canadian-style, single-payer system.

A single-payer system may be at-

The elderly are one of the largest groups of health-care consumers. Will reform ensure their care *and* the care of utility employees?

tractive to employers who are footing the entire cost of their employees' benefits, and who figure they can cut costs by entering a larger national pool funded by other employers and the federal and state governments. But that approach has no chance of passing Congress, where support for such a system has peaked at about a quarter of the membership of the House. Americans generally are apprehensive of anything that smacks of socialized medicine.

The Clinton administration's top advisors clearly lean toward some form of managed competition, although some of the President's counselors urge that competition be balanced by price controls, so that in effect we would have competition but within a national health budget set by a governing board. Republicans (and many Democrats) who may favor the managed-competition aspect of this approach are likely to balk at such measures they are mindful of Nixon-era wage and price controls. They've also heard stories about doctors in Canada (who operate under an annual budget) calling it quits for the budgeted year when they bump up against their annual ceiling for patient care. As the joke goes, "In Canada, where do you find your doctor in early December? In Florida."

The latest news is that the Clinton plan for health-care reform is due in September. Though it is conjecture, many believe that the plan has already moved away from managed competition to favor a simpler employer-based system, supplemented by federal assistance to the unemployed to help them purchase health care. Such an approach would build on the fact that the great majority of Americans—85 percent—are covered through their employer, Medicare or Medicaid, the Veterans Administration, or private insurance. That leaves a relatively small universe without coverage, most of whom would be covered through mandatory employer-provided benefits.

What we could see, then, due to a reluctance or inability on Congress' part to take on comprehensive reform, is support for an explicitly employer-funded health-care system (which might mandate a percentage of payroll that would go to coverage, for example), an approach sure to meet adamant opposition from a politically powerful small-business lobby. Another way for Congress to shirk responsibility on this issue would be to create a program that gives great flexibility to the states. That would please many states, but large multistate businesses would oppose it.

If Congress should go along with this simple plan to extend coverage without addressing broader issues of escalating costs, we may see the immediate social problem of the uninsured and underinsured resolved with only minimal impact on total expenditures for health care.

And if that is the outcome, we will have failed to achieve reform.

That's why it is critical that the utility industry be active in the lobbying effort on this legislation. Our companies have a tremendous stake in this debate. Whether individually, or with other payers, we have a duty to our shareholders and employees to promote a solution to the problem of uncontrolled health-care costs. ◆

supply side could save customers millions of dollars. Also, many older office buildings in the New York metropolitan area cannot accommodate additional electrical load. With energy-efficient machines, landlords have a way to avoid costly upgrades to their own electrical systems.

Encouraging a Market

In January 1993, EPA announced that it had extended the Energy Star program to include laser printers as well, which must power down and consume no more than 45 watts in sleep mode to qualify under the program.

In all, there are approximately 100 manufacturers participating in the Energy Star program, and they account for about 65 percent of U.S. sales of desktop computers and 90 percent of the laser-printer market. Each company has signed an agreement with EPA and will introduce desktop computers, printers, or monitors that meet the requirements. As a federal agency, of course, EPA does not use the logo to endorse a particular company.

According to participating manufacturers, most companies expect to convert a majority of their product lines to qualify for the logo within just a couple of years—and with no performance sacrifice. As far as extra cost to consumers, many computer-industry observers expect premiums for these green machines to be anywhere from 10 to 30 percent for the next year or so, with the competition factor pulling the price back thereafter.

To jumpstart the market, President Clinton, in his April Earth Day speech, announced that the federal government is committed to purchasing products bearing the Energy Star logo—and the government is the largest buyer of computers in the world. His executive order directs U.S. agencies to acquire only desktop computers, monitors, and printers that meet the requirements (provided that they are commercially available and meet the agencies' performance needs). The order takes effect in October and is estimated to save taxpayers $40 million in electricity costs annually.

A New Product Expo

Con Edison's interest in the acceptance of Energy Star equipment stems from the many benefits the machines will provide to businesses, property-owners, other customers, and the environment. In June, a couple of weeks after the official launch of EPA's program, the utility hosted the Brightened Office Expo in New York City, where several Energy Star manufacturers displayed their latest products.

Besides a list of the exhibitors and their contact information:

- Acer America Corporation (San Jose, CA; 408/432-6200)
- Advanced Logic Research, Inc. (Irvine, CA; 714/581-6770)
- Aztech nn Research Corporation (Glendale, CA; 818/962-1126)
- Apple Computer, Inc. (Cupertino, CA; 408/996-1010)
- AST Research, Inc. (Irvine, CA; 714/727-4141)
- Compaq Computer Corporation (Houston, TX; 713/370-0670)
- Hewlett-Packard (Palo Alto, CA; 415/857-1501)
- Intel Corporation (Santa Clara, CA; 408/765-8080)
- IBM Corporation (Armonk, NY; 914/765-1900)
- IDEK (Iyama North America, Inc. (Warminster, PA; 215/957-6543)
- Nanao USA Corporation (Torrance, CA; 310/325-5202)
- NCR Corporation (Dayton, OH; 513/445-5000)
- PureePower Technologies (San Jose, CA; 408/954-8880)
- Samsung Electronics America (Ledgewood, NJ; 800/446-0262)
- Sequence Electronics (Carleton Place, ON; 613/257-4773)
- Technology Marketing Partners, Inc. (Mountain View, CA; 415/940-7805)
- Western Digital Corporation (Irvine, CA; 714/932-5000)

FINANCIAL REVIEW

EARNINGS LEAP 25.6 PERCENT

Investor-owned electric utility earnings per share (EPS) before extraordinary items increased to $0.54 cents for the first quarter of the year, up $0.11 from the first quarter of 1992. Strong electricity sales, caused by colder-than-usual weather, was primarily responsible for the increase.

EPS after extraordinary items and the cumulative effect of a change in accounting principle increased 19.6 percent to $0.55. About half of the gain for the quarter reported under cumulative effects is attributable to companies' adopting Statement of Financial Accounting Standards 109, "Accounting for Income Taxes" (SFAS 109). The remaining gain is largely associated with the recognition of unbilled revenues.

Income Statement

Total operating revenue increased 5.0 percent from $37.8 billion in the first quarter of 1992 to $39.7 billion in the first quarter of 1993. In addition to the weather, 1992 rate increases of $2.6 billion and higher fuel costs recovered through fuel clause adjustment mechanisms contributed to the revenue increase. (See Table 1.)

Almost all operating expense items increased over last year's first quarter. In total, they rose 4.8 percent to $32.5 billion for the quarter.

Allowance for funds used during construction (AFUDC) jumped 19.7 percent from $259 million in the first quarter of 1992 to $310 million in the first quarter of 1993. The increase is mainly associated with a nuclear unit currently under construction. Likewise, phase-in plans totaled $114 million, up sharply from the $19 million recorded for first quarter 92. Here too the increase reflects the impact of nuclear plants, in this case the recognition of plants that were previously deferred.

The pre-tax interest coverage with AFUDC increased to 2.77 times, up from

TABLE 1

INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY STATEMENT OF INCOME

(Millions of Dollars)

	Three Months Ending March 31,			Twelve Months Ending March 31,		
	1993	1992r	Change[2]	1993	1992r	Change[2]
Total Electric Operating Revenues[1]	$39,677	$37,790	5.0	$161,678	$158,457	2.0
Electric Operating Expenses						
Fuel	$7,210	$6,847	5.3	$28,801	$29,088	(1.0)
Purchased Power & Net Interchange	4,362	4,033	8.2	18,074	16,805	7.5
Other Operation & Maintenance	10,607	10,374	2.2	43,501	42,808	1.6
Depreciation & Amortization	4,552	4,293	6.0	17,598	16,780	4.9
Costs Deferred Under Rate Phase-In Plans	140	78	79.6	135	(165)	N.M.
Taxes Other Than Income Taxes	3,360	3,270	2.8	13,089	12,698	3.1
Income Taxes: Federal & Other	1,976	1,758	12.4	7,709	8,301	(7.1)
Deferred Income Taxes	395	466	(15.2)	2,458	1,689	45.6
Investment Tax Credits, Net	(80)	(92)	(13.3)	(416)	(265)	57.1
Total Electric Operating Expenses	$32,522	$31,027	4.8	$130,950	$127,739	2.5
Electric Operating Income	$7,155	$6,763	5.8	$30,729	$30,718	0.0
Other Utility Operating Income	857	758	13.1	1,616	1,463	10.5
Total Utility Operating Income	$8,012	$7,521	6.5	$32,345	$32,181	0.5
Other Income & Deductions, Net	$476	$197	141.1	$955	($878)	N.M.
Phase-In Deferrals	26	59	(56.8)	158	385	(59.0)
Allowance for Other Funds Used During Construction	161	138	17.2	628	619	1.4
Total Income Before Interest Charges	$8,675	$7,915	9.6	$34,086	$32,307	5.5
Interest Charges						
Interest on Long-Term Debt	$3,537	$3,596	(1.7)	$14,389	$14,748	(2.4)
Other Interest Expenses & Charges	478	540	(11.5)	1,817	2,065	(12.0)
Allowance for Borrowed Funds Used During Construction	(149)	(121)	23.3	(542)	(522)	3.9
Net Interest Expenses & Charges	$3,865	$4,015	(3.7)	$15,663	$16,290	(3.8)
Net Income Before Extraordinary Items	$4,810	$3,900	23.3	$18,423	$16,017	15.0
Extraordinary Items	0	(2)	N.M.	(13)	(339)	(96.1)
Cumulative Effect of a Change in Accounting Principle	115	256	(54.9)	130	256	(49.3)
Net Income	$4,925	$4,154	18.6	$18,540	$15,935	16.3
Preferred Dividends Declared	451	497	(9.2)	1,959	1,968	(0.5)
Net Income Available for Common	$4,474	$3,657	22.4	$16,581	$13,966	18.7
Common Dividends Declared	3,766	3,694	2.0	14,650	14,128	3.7
Additions to Retained Earnings	$708	($38)	N.M.	$1,931	($161)	N.M.
Avg. Shares Outstanding (Millions)	8,134	7,945	2.4	8,108	7,919	2.4
Earnings Per Share Before Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle	$0.54	$0.43	25.6	$2.03	$1.77	14.7
Earnings Per Share After Extraordinary Items and the Cumulative Effect of a Change in Accounting Principle	$0.55	$0.46	19.6	$2.05	$1.76	16.5
Common Dividends Per Share	$0.46	$0.46	0.0	$1.81	$1.78	1.7

Source: EEI Survey Data and Standard and Poor's Compustat Services, Inc.
[1] Revenues are adjusted for intra-industry electricity sales to resale.
[2] Percent changes may reflect rounding.
r - Revised to reflect company restatements.
N.M. - Not Meaningful.

2.46 times for last year's first quarter. The pre-tax coverage without AFUDC changed from 2.40 to 2.69 times. The increases in these ratios are due both to increased earnings and to lower interest expenses.

Return on average common equity excluding net non-recurring items was 11.8 percent for the twelve months ending March 31. The dividend payout ratio after extraordinary items and excluding net non-recurring items was 78.7 percent for the same period.

Balance Sheet

Total assets as of March 31, 1993, stood at $551.6 billion, up 10 percent from the $501.4 billion recorded a year earlier. (See Table 2.) The increase reflects the industry's implementation of SFAS 109. SFAS 109 requires electric utilities to establish additional deferred tax assets and liabilities for certain temporary timing differences and to adjust deferred tax accounts for changes in income tax rates. The adjustments required by SFAS 109 were recorded to deferred tax balance sheet accounts, with offsetting adjustments to regulatory assets and liabilities.

Total capitalization increased 3.3 percent. The most significant increase resulted from a 4.1 percent rise in common stock (reflecting new stock issuance) and a 4.2 percent increase in retained earnings. Long-term debt increased 2.9 percent as low yields spurred many companies to issue long-term debt. The embedded cost of long-term debt dropped to 8.1 percent for the twelve months ending March 31 from 8.5 percent for the previous twelve months.

TABLE 2
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY BALANCE SHEET
(Millions of Dollars)

Assets	March 31, 1993	March 31, 1992r	%Change[2]
Utility Plant[1]			
Utility Plant (Including Nuclear Fuel)	$556,279	$535,733	3.8
Less Accumulated Depreciation	186,629	172,570	8.1
Total	$369,650	$363,163	1.8
Construction Work in Progress	25,629	22,648	13.2
Net Utility Plant	$395,279	$385,812	2.5
Investments	$32,240	$30,365	6.2
Current Assets	49,922	46,412	7.6
Deferred Debits	74,190	38,786	91.3
Total Assets	$551,631	$501,375	10.0
Capitalization & Liabilities			
Capitalization			
Common Stock	$102,195	$98,216	4.1
Retained Earnings	55,365	53,150	4.2
Preferred Stock	25,062	24,736	1.3
Long-Term Debt	180,420	175,389	2.9
Total Capitalization	$363,042	$351,491	3.3
Current Liabilities			
Short-Term Debt	$8,743	$9,259	(5.6)
Long-Term Debt Due Currently	11,989	9,000	33.2
Other Current Liabilities	39,473	36,649	7.7
Total Current Liabilities	$60,206	$54,908	9.6
Deferred Credits			
Capital Lease Obligations, Non-Current Portion	$3,343	$3,639	(8.1)
Accumulated Deferred Income Taxes	81,231	55,526	46.3
Accumulated Deferred Investment Tax Credits	14,197	14,625	(2.9)
Other Deferred Credits	29,612	21,188	39.8
Total Deferred Credits	$128,383	$94,977	35.2
Total Capitalization & Liabilities	$551,631	$501,375	10.0

SOURCE: EEI Survey Data and Standard and Poor's Compustat Services, Inc.
[1] Includes non-electric utility plant. [2] Percent changes may reflect roundings.
r - Revised to reflect company restatements.

STATISTICAL REVIEW

SALES UP 2.4 PERCENT

TABLE 1

FIRST QUARTER CUSTOMERS, SALES, AND REVENUE DATA FOR INVESTOR-OWNED ELECTRIC UTILITIES

	Three Months Ending March 31,			Twelve Months Ending March 31,		
	1993	1992	%Change	1993	1992	%Change
Number of Customers						
Residential	75,938,105	75,232,447	0.9	75,548,780	74,823,831	1.0
Commercial	9,475,794	9,401,697	0.8	9,465,190	9,379,491	0.9
Industrial	389,255	385,609	0.9	401,361	396,417	1.2
Street & Highway	146,624	145,128	1.0	147,334	145,729	1.1
Other Public Authorities	174,054	170,836	1.9	172,739	170,106	1.5
Railroads	23	23	0.0	23	23	0.0
Interdepartmental	493	471	4.7	528	468	12.8
Total Customers	86,124,348	85,336,211	0.9	85,735,954	84,916,065	1.0
Electricity Sales (MWh)						
Residential	185,508,963	177,267,975	4.6	688,762,864	693,241,665	(0.6)
Commercial	152,111,311	148,518,957	2.4	629,594,038	625,704,449	0.6
Industrial	175,363,913	175,215,924	0.1	727,774,638	720,899,596	1.0
Street & Highway	2,781,195	2,800,786	(0.7)	10,584,593	10,561,687	0.2
Other Public Authorities	14,309,234	13,873,875	3.1	58,749,387	55,874,988	5.1
Railroads	662,443	642,635	3.1	2,507,196	2,533,779	(1.0)
Interdepartmental	170,811	241,703	(29.3)	1,019,382	1,234,833	(17.4)
Total Sales	530,907,870	518,561,855	2.4	2,118,992,098	2,110,050,997	0.4
Revenues ($000)						
Residential	15,151,128	14,561,511	4.0	59,171,522	59,013,924	0.3
Commercial	11,469,952	11,168,106	2.7	49,230,744	48,396,994	1.7
Industrial	8,518,511	8,553,088	(0.4)	36,803,558	36,412,257	1.1
Street & Highway	374,310	331,352	13.0	1,355,572	1,293,608	4.8
Other Public Authorities	710,337	686,312	3.5	2,960,440	2,881,244	2.7
Railroads	42,665	42,573	0.2	173,758	177,810	(2.3)
Interdepartmental	22,658	26,415	(14.2)	76,450	82,361	(7.2)
Total Revenues	36,289,561	35,369,356	2.6	149,772,045	148,258,199	1.0

Source: Edison Electric Institute, Statistics Department